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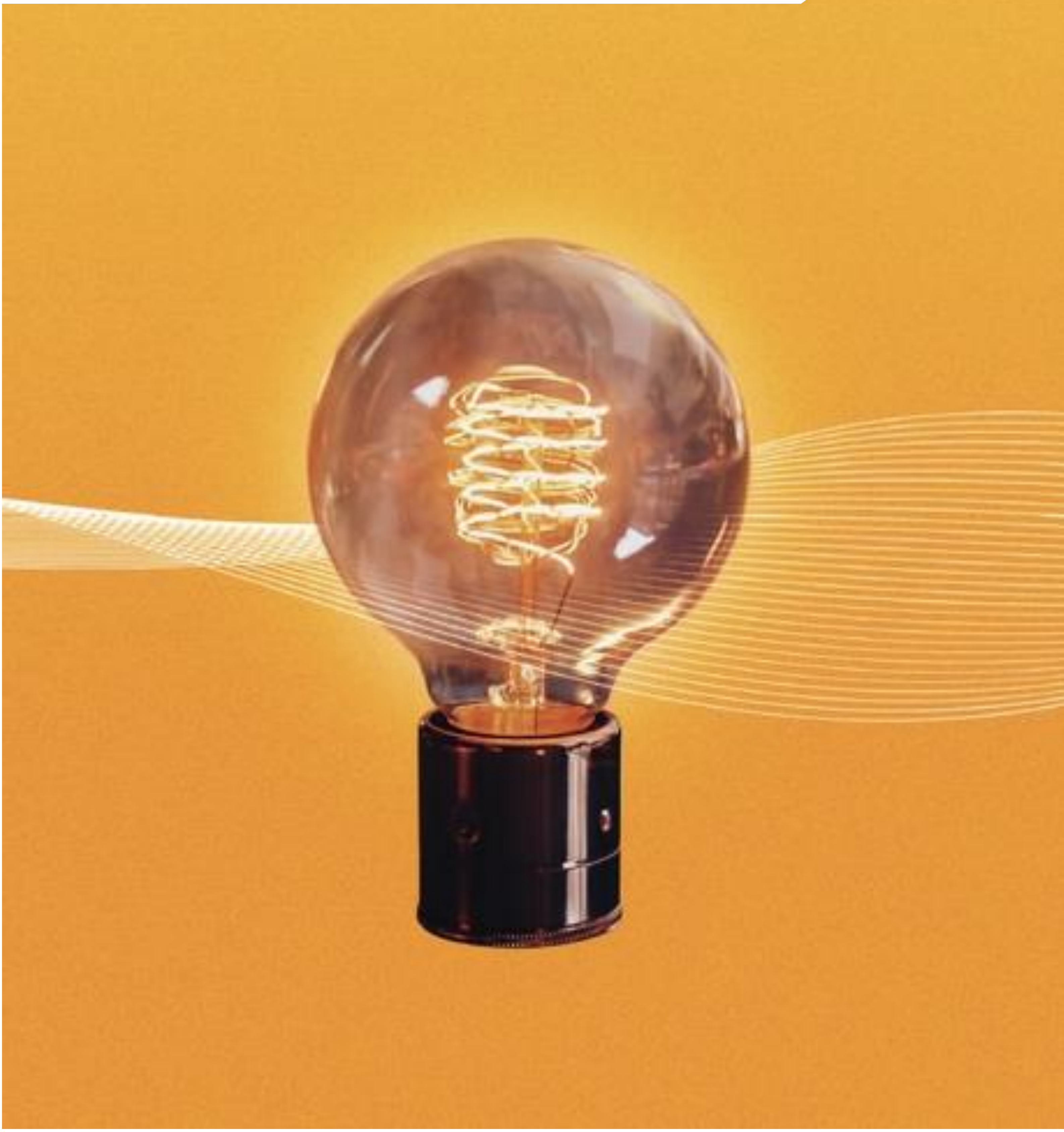
National Grid ESO
Electricity Capacity Report

31 May 2022

(Submitted to Department for Business, Energy and Industrial Strategy)

Results from the work undertaken by National Grid ESO for BEIS to recommend the capacity to secure through the Capacity Market.



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National Grid ESO Electricity Capacity Report

1. Executive Summary

This Electricity Capacity Report (ECR) summarises the modelling undertaken by National Grid ESO in its role as the Electricity Market Reform (EMR) Delivery Body to support the decision by the Government on the amount of capacity to secure through the Capacity Market (CM) auctions for delivery in 2023/24 and 2026/27.

The Government requires National Grid ESO to provide it with a recommendation for each auction year based on the analysis of credible scenarios and sensitivities to ensure its policy objectives are achieved.

National Grid ESO has also considered the recommendations included in the Panel of Technical Experts (PTE[1]) report[2] on the 2021 process. This led to National Grid ESO undertaking steps to improve this year's analysis. In addition, there has been continued engagement with the Department for Business, Energy and Industrial Strategy (BEIS), the PTE and the Office of Gas and Electricity Markets (Ofgem) throughout the year to enable them to scrutinise the modelling approach and assumptions used.

Chapter 2 of this report describes stakeholder engagement. Chapter 3 describes the modelling approach, including the tools used and enhancements made, for this year's analysis. Chapter 4 covers the scenarios and sensitivities modelled. Chapter 5 details the de-rating factors for generating technologies, storage, demand side response (DSR) and interconnected countries. Chapter 6 and Chapter 7 contain modelling results and the recommended capacity to secure for the 2023/24 T-1 and 2026/27 T-4 auctions, respectively. Finally, the Annex contains further details on the assumptions and methods that underpin our recommendations as well as a summary of our previous ECR recommendations and auction outcomes to-date. In addition to this year's report, we have also published a Data Workbook[3] that contains the data behind the numerical tables and charts in the ECR.

National Grid ESO is shocked and saddened by the events happening due to Russia's invasion of Ukraine. We know the impacts of Russia's war are being felt beyond Ukraine and these events are challenging us to consider the impact on security of supply to the British energy system. There is uncertainty as to how these events could impact electricity security of supply in Great Britain for winter 2023/24 or 2026/27. The demand and supply assumptions used to inform our recommendations do not explicitly consider the impact of these events. However, we recognise that there could be a material impact on our recommendations should the impact of Russia's war cause them to change significantly. We propose to keep this situation under review in the coming months. We have an opportunity, as part of the well-established Capacity Market annual process, to reflect on any new information when we undertake the Adjustment to the Demand Curve after prequalification in the autumn. This could lead to our recommendations being revised ahead of the auctions.

[1] https://www.gov.uk/government/groups/electricity-market-reform-panel-of-technical-experts
[2] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/999459/panel-technical-experts-report-on-2021-electricity-capacity-report.pdf
[3] To be published at https://www.emrdeliverybody.com/cm/home.aspx

1.1 Results and Recommendations

Table 1 shows National Grid ESO's recommendations for the target capacity for the 2022 auctions: T-1 delivering for 2023/24 and T-4 for 2026/27. Some adjustments may be required to set the final target capacity for each auction following prequalification; this is described in Chapters 6 and 7. While these are our recommendations, the decisions on whether to run an auction and on the final target capacity rest with the Secretary of State. The final target capacity will be published in the Final Auction Guidelines after prequalification.

Table 1: Recommendations for the target capacity for delivery in 2023/24 and 2026/27 for the T-1 and T-4 Capacity Market auctions

	2023/24 T-1	2026/27 T-4
Recommended target capacity	5.8 GW	43.9 GW

Our recommendations are based on assessing the capacity required to meet the Reliability Standard of 3 hours loss of load expectation (LOLE) across a credible range of scenarios. Our modelling assumes that the Base Case and Future Energy Scenarios (FES) cover uncertainty in future electricity demand and supply. This includes uncertainty in demand, generation, storage, demand side response (DSR) and interconnection capacity.

The scenarios we have modelled are listed as follows:

- Base Case[4] (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Falling Short (FS)

We also model sensitivities to assess uncertainty that is not covered by the scenarios. The sensitivities cover uncertainty in non-delivery, over-delivery, station availability, weather, and peak demand. Sensitivities are only applied to the Base Case. Each of the sensitivities is considered credible in that it is either evidence-based (i.e. it has occurred in recent history) or it addresses statistical uncertainty caused by the small sample sizes used for some of the input variables. Section 4.8 describes each sensitivity and how it has been modelled.

The recommendation for the target capacity to secure is informed by a cost-optimised method called Least Worst Regret (LWR). LWR seeks to balance the costs of securing capacity against the costs of unserved energy. The cost assumptions used in the LWR calculation are unchanged from previous ECR analysis. We assume a cost of capacity of £49/kW/year net Cost of New Entry (CONE) and an energy unserved cost (referred to as the Value of Lost Load (VoLL)) of £17,000/MWh[5]. This is consistent with a Reliability Standard of 3 hours LOLE[6]. Our recommendations for the target capacity correspond to the value on the CM demand curve equal to net CONE. The clearing price in the auction may

[4] The Base Case (BC) is based on the FES Five Year Forecast to 2026/27, then aligned to System Transformation from 2027/28 onwards to provide a full 15-year view.
[5] Note that the Government's Reliability Standard was derived using a slightly different capacity cost of £47/kW/year based on the gross CONE of an Open Cycle Gas Turbine (OCGT). For more information, see: https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/267613/Annex_C_-_reliability_standard_methodology.pdf
[6] The Reliability Standard of 3 hours LOLE is given by the ratio of net CONE / VoLL.

be different to net CONE, resulting in the cleared capacity being different to the target capacity.

1.1.1 2023/24 T-1 Modelling Results and Auction Recommendation

The outcome of the LWR calculation results in a recommended capacity to secure for delivery in 2023/24 via the T-1 auction of **5.8 GW** derived from the requirement of the 2.8 GW non-delivery sensitivity. Our recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation also accounts for any capacity already secured for delivery in 2023/24 from earlier T-3 and T-4 auctions that is assumed in the Base Case. Our modelling shows that if we secure 5.8 GW in the T-1 auction, then we would expect this to result in a Base Case LOLE of 0.4 hours/year for winter 2023/24, with an associated de-rated margin of 3.9 GW or 6.5%. This is broadly similar to recent winter margins reported in National Grid ESO Winter Outlook Reports[7]. While the Base Case LOLE is lower than 3 hours LOLE, we believe this is appropriate in order to provide greater resilience to credible downside risks such as non-delivery.

When compared to the analysis for 2023/24 in the 2019 ECR, our recommendation is 4.6 GW higher than the 1.2 GW originally set aside by the Secretary of State for the T-1 auction. This net difference is the result of 6.9 GW of increases offset by 2.3 GW of decreases since the 2019 ECR.

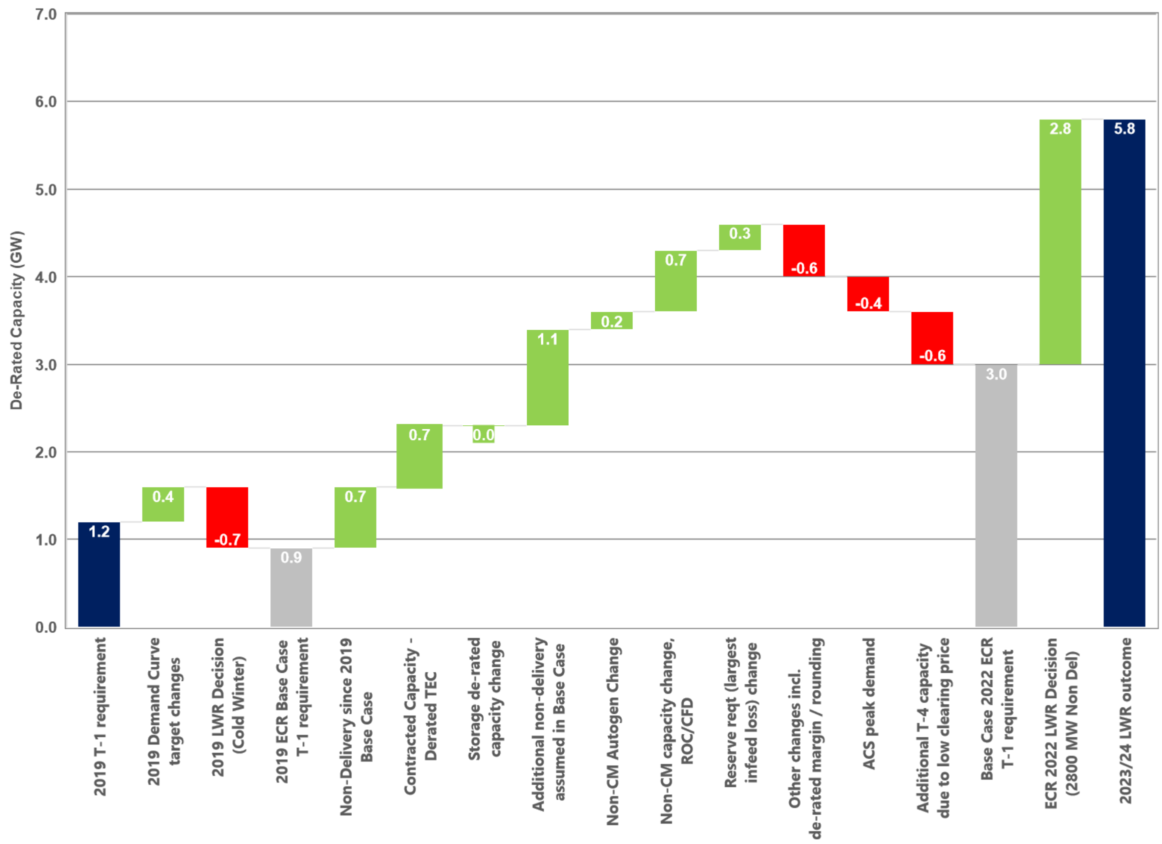
The increases result from: known non-delivery (units in the 2019 Base Case awarded agreements in previous auctions covering 2023/24 that are now known not to be able to honour their agreements); additional assumed non-delivery in the Base Case based on market intelligence of capacity providers who we do not currently expect to meet their obligations for 2023/24; the contracted capacity covering 2023/24 from previous auctions being greater than our latest view of de-rated Transmission Entry Capacity (TEC); slightly lower levels of assumed opted-out or ineligible autogeneration; lower non-CM renewable capacity than in the 2019 Base Case; a slightly higher reserve requirement for largest infeed loss; and a change in the range of scenarios and sensitivities modelled resulting in a higher LWR outcome compared to the Base Case than in 2019. In addition, the demand curve adjustments made in 2019 following prequalification for the T-4 auction and conclusion of the T-3 auction for 2022/23 (a reduction due to capacity awarded multi-year agreements covering 2023/24 in the T-3 auction, a reduction relating to long-term short term operating reserve (STOR) outside of the CM combined with a small increase due to non-CM autogeneration) are no longer relevant for the T-1 auction as prequalification for the T-1 auction has not yet taken place and the 2022 Base Case generation assumptions are different to the 2019 Base Case assumptions.

The decreases arise from: a slightly lower peak demand for 2023/24; a reduction due to over-securing in the 2023/24 T-4 auction and a net reduction due to some other changes.

Figure 1 shows how the original 1.2 GW set aside for delivery in 2023/24 via the T-1 auction (derived from the 2019 Cold Winter sensitivity) has changed into a LWR outcome of 5.8 GW (derived from the 2022 Base Case 2.8 GW non-delivery sensitivity) as a result of the net increase described above.

[7] https://www.nationalgrideso.com/document/212691/download

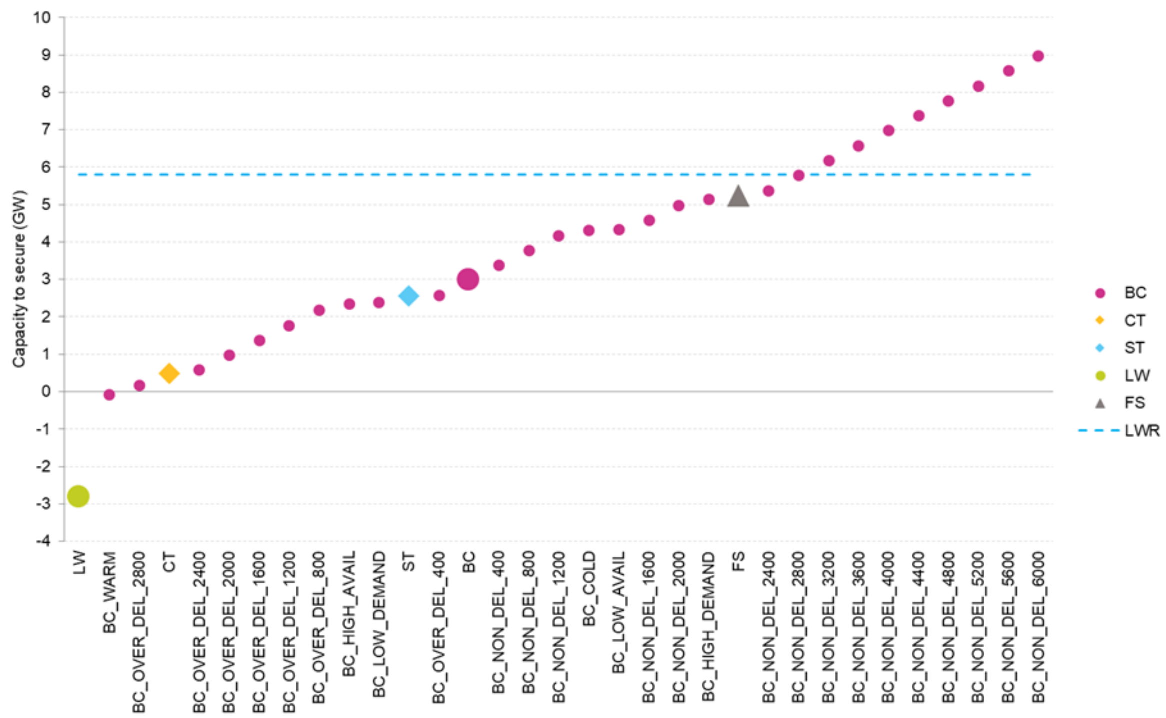
Figure 1: Comparison with original 2023/24 T-1 requirement (de-rated)



Note: intermediate totals in grey above show requirements for 2019 Base Case and 2022 Base Case

Figure 2 shows the capacity to secure from each of the scenarios and sensitivities modelled and our recommendation of 5.8 GW derived from the LWR outcome.

Figure 2: LWR outcome and other cases modelled comparison – 2023/24



1.1.2 2026/27 T-4 Modelling Results and Auction Recommendation

The outcome of the LWR calculation results in a recommended capacity to secure for the delivery in 2026/27 via the T-4 auction of **43.9 GW** derived from the requirement of the 3.2 GW non-delivery sensitivity. Our recommendation corresponds to the value on the CM demand curve for the net CONE capacity cost. The recommendation also accounts for any capacity already secured for delivery in 2026/27 via earlier T-3 and T-4 auctions that is assumed in the Base Case. Our modelling shows that if we secure 43.9 GW in the T-4 auction, then we would expect this to result in a Base Case LOLE of 0.3 hours/year for winter 2026/27, with an associated de-rated margin of 3.8 GW or 6.1%. This is broadly similar to recent winter margins reported in National Grid ESO Winter Outlook Reports[8]. While the Base Case LOLE is lower than 3 hours LOLE, we believe this is appropriate in order to provide greater resilience to credible downside risks such as non-delivery.

When compared to the T-4 analysis for 2025/26 in the 2021 ECR, the 2022 ECR recommendation for 2026/27 is 0.2 GW lower. This net difference is the result of 5.0 GW of increases offset by 5.2 GW of decreases since the 2021 ECR.

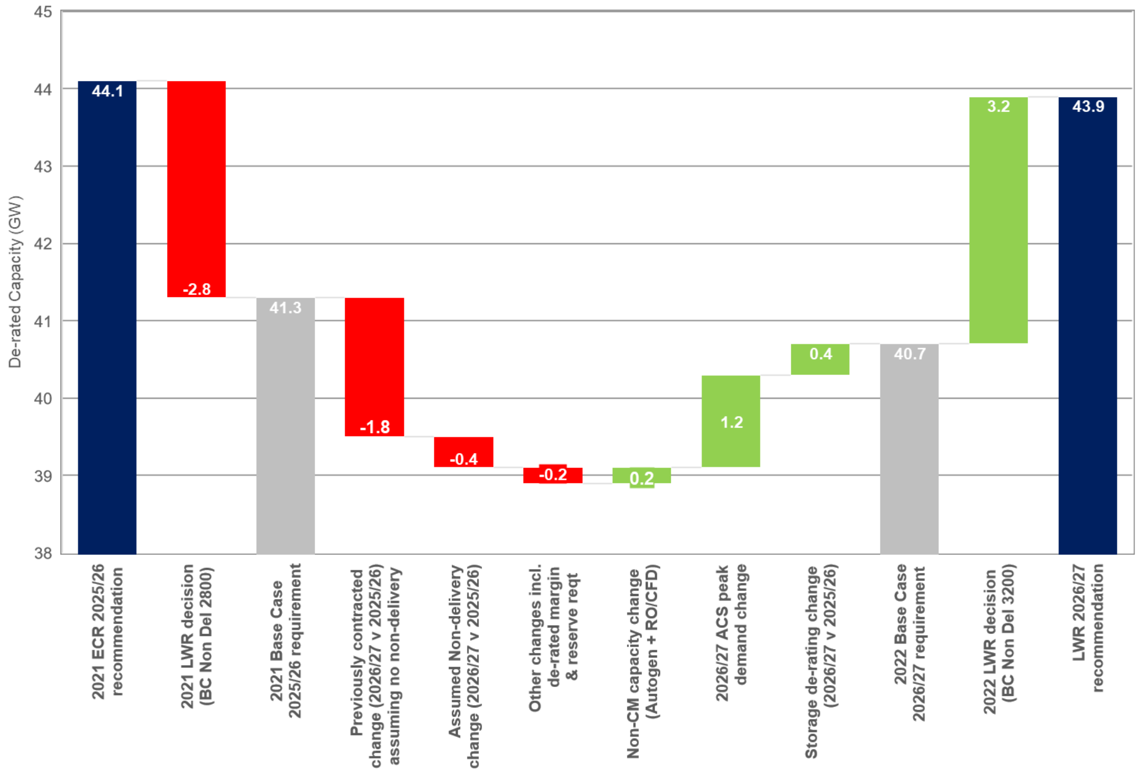
The increases result from: a higher peak demand for 2026/27 than for 2025/26 in the 2021 ECR; slightly lower non-CM capacity (assumed opted-out or ineligible autogeneration and non-CM renewable capacity); a reduction in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards; and a change in the range of scenarios and sensitivities modelled resulting in a slightly higher LWR outcome compared to the Base Case than in 2021.

The decreases arise from: an increase in previously contracted capacity from CM units awarded multi-year agreements in recent auctions (excluding the additional non-delivery assumed in the Base Case); a lower level of non-delivery assumed in the Base Case; and a small net decrease due to other changes.

Figure 3 shows how the original 44.1 GW requirement for delivery in 2025/26 from the T-4 auction (derived from the 2021 Base Case 2.8 GW non-delivery sensitivity) has changed into a recommendation of 43.9 GW as a result of the 0.2 GW net decrease described above.

[8] https://www.nationalgrideso.com/document/212691/download

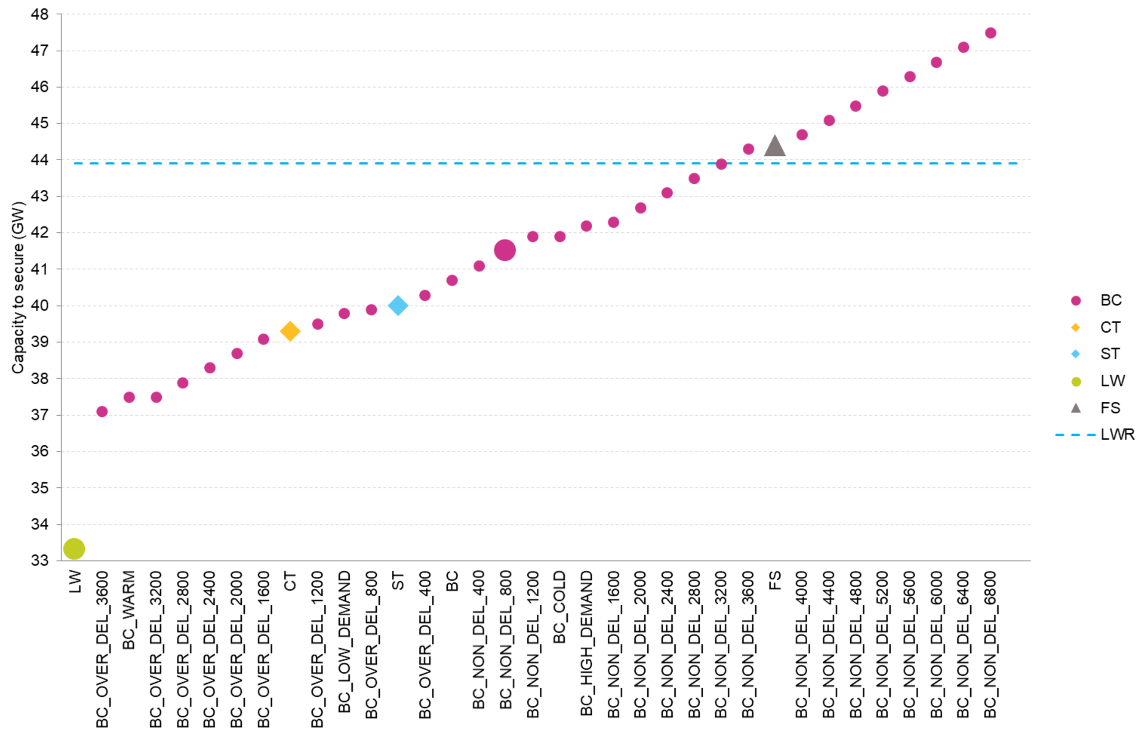
Figure 3: Comparison with recommended 2025/26 T-4 requirement in 2021 ECR



Note: intermediate totals in grey above show requirements for 2021 Base Case and 2022 Base Case

The chart in Figure 4 shows the capacity to secure from each of the scenarios and sensitivities modelled and our recommendation of 43.9 GW derived from the LWR outcome.

Figure 4: LWR outcome and other cases modelled comparison – 2026/27



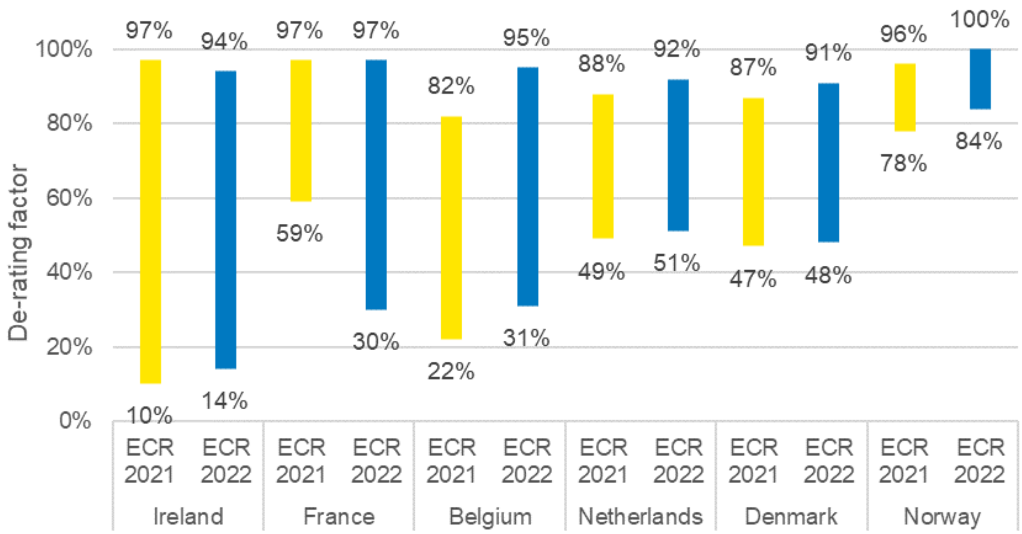
1.2 Interconnected Countries De-rating Factor Ranges

Figure 5 shows the de-rating factor ranges for interconnected countries based on the modelling we have done using our pan-European market model, BID3. These cover existing and potential future interconnected countries. These ranges inform the choice of de-rating factors for the T-4 auction for 2026/27 delivery, which are ultimately decided by the Secretary of State in consultation with the PTE. The wide ranges indicate that there is significant uncertainty in the European outlook, and while we consider this to be appropriately reflected in our modelling, it highlights the challenge in assigning a single de-rating factor value for each individual interconnector to participate in the auction. We have not provided de-rating factor ranges for the T-1 auction as all interconnectors that we expect to be operational for the start of the delivery year have already been awarded agreements in the T-4 auction for delivery in 2023/24.

In this year's modelling, we have continued to use the same method since the 2020 ECR for calculating the contribution interconnectors make to security of supply during times of system stress. This means that the stress periods used in the interconnector analysis are more consistent with the definition in the Capacity Market rules. It also means that the methodology for interconnectors is better aligned with other technologies such as storage and renewables. Further details on our modelling approach are described in Section 5.2. This approach is also more consistent with work that has been undertaken by ENTSO-E to develop a consistent methodology to determine the maximum level of cross-border capacity that can participate in capacity mechanisms. This work has been undertaken as part of the Clean Energy Package (Article 26 of Regulation (EU) 2019/943). The methodology has now been approved and details can be found on the European Union Agency for the Cooperation of Energy Regulators (ACER) website[9].

The modelled ranges do not include an allowance for interconnector import constraints in Great Britain or for technical reliability. Adjustments for technical reliability are determined by BEIS.

Figure 5: Modelled de-rating factor ranges for interconnected countries



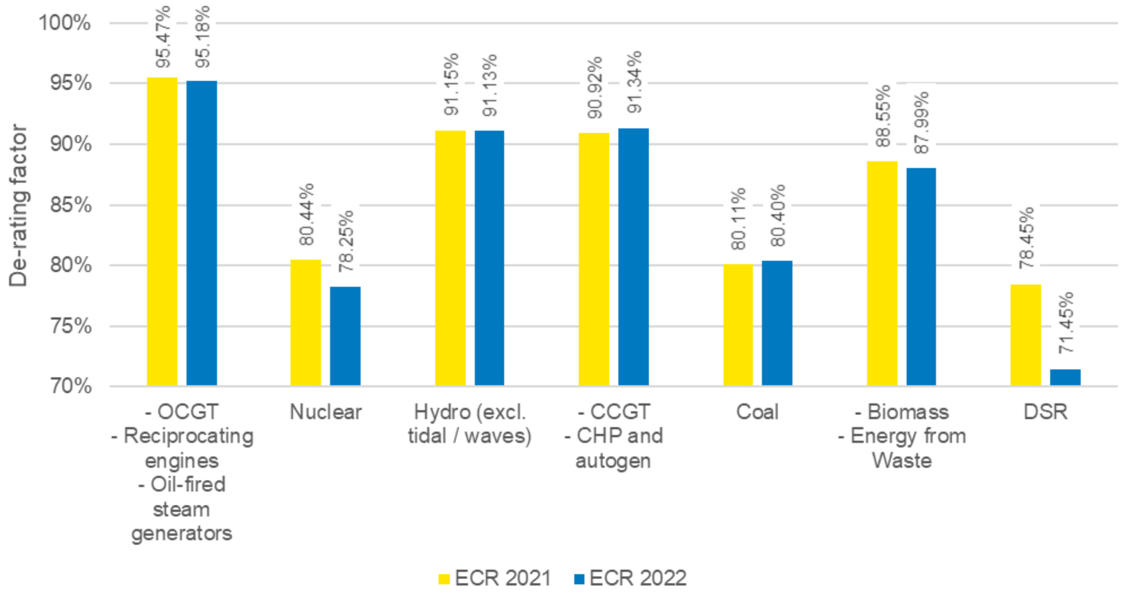
Note: ECR 2021 refers to 2025/26 T-4 values and ECR 2022 refers to 2026/27 T-4 values.

[9] https://www.acer.europa.eu/Media/News/Pages/ACER-decides-on-common-rules-for-cross-border-participation-in-electricity-capacity-mechanisms-.aspx

1.3 De-rating Factors for Conventional Plants, Storage and Renewables

The following figures show the de-rating factors for conventional plants (Figure 6), storage (Figure 7 and Figure 8) and renewables (Figure 9 and Figure 10). De-rating factors from the previous year's report are shown for comparison. No changes have been made to the methodology used to determine these de-rating factors. Further details are included in Chapter 5 and tabular versions of the results are found in the companion ECR Data Workbook.

Figure 6: De-rating factors for conventional plants



Note: Conventional plant de-rating factors apply to both the 2023/24 T-1 and 2026/27 T-4 auctions. See Annex A.5.6 Conventional Plant Types for descriptions of each technology class.

Figure 7: De-rating factors for duration limited storage T-1 comparison

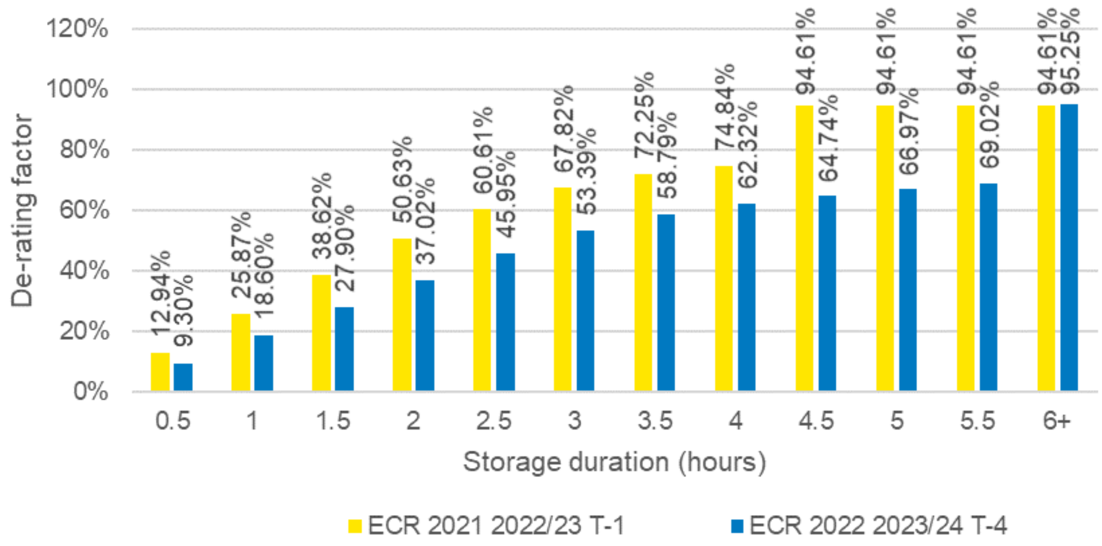


Figure 8: De-rating factors for duration limited storage T-4 comparison

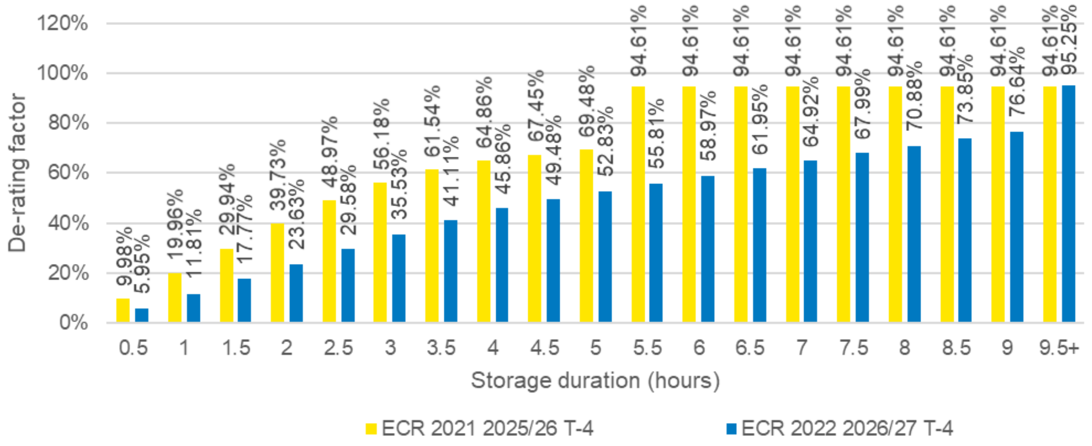


Figure 9: De-rating factors for renewables T-1 comparison

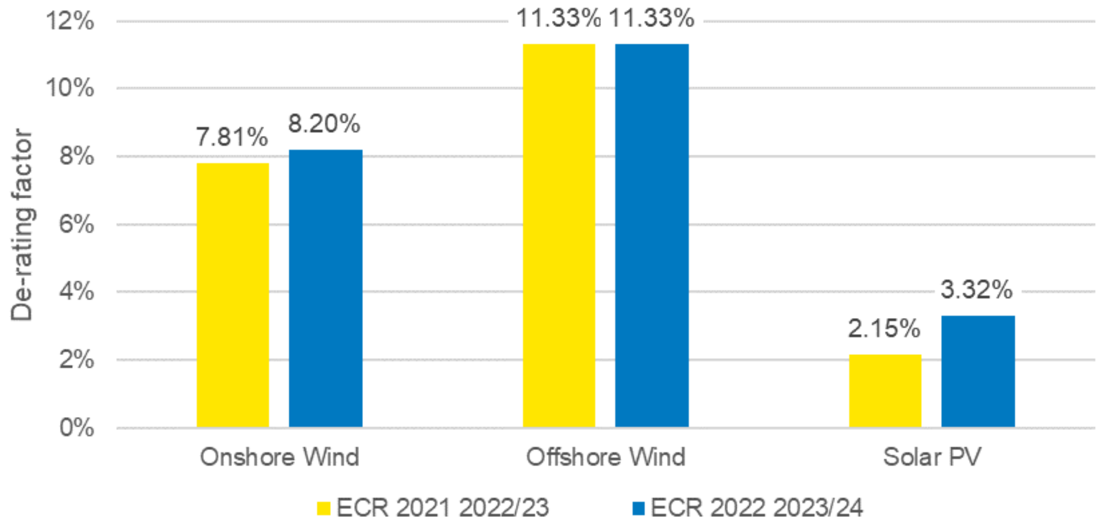
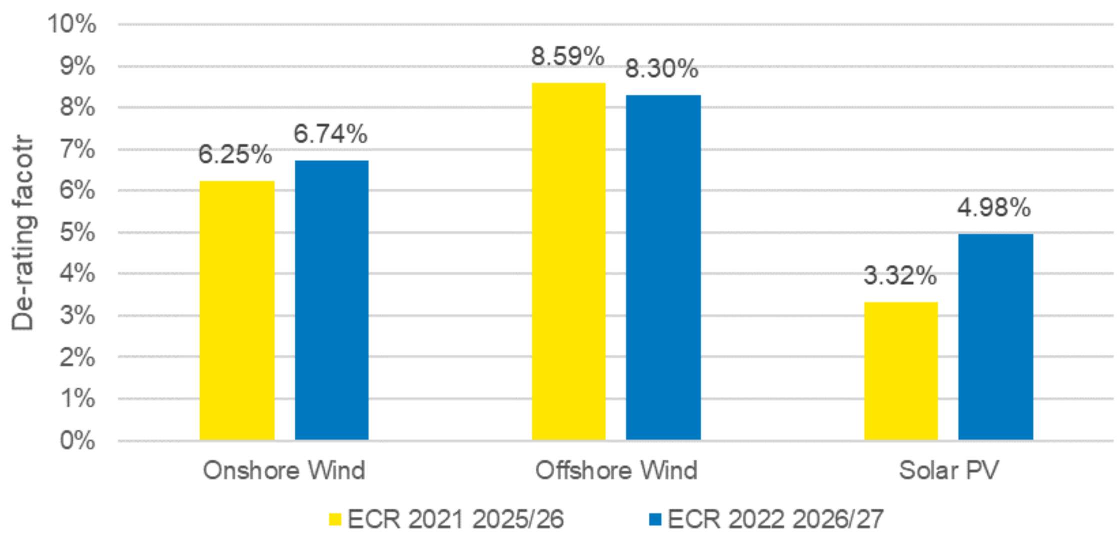


Figure 10: De-rating factors for renewables T-4 comparison



This year, there is a higher level of duration-limited storage capacity in the 2022 ECR Base Case than in the 2021 ECR Base Case particularly for the T-4 year (see Annex A.7 for more details). As a result of this increased capacity, the duration threshold corresponding to 95% of stress events has increased from 4.5 hours to 6 hours in the T-1 year and increased from

5.5 hours to 9.5 hours in the T-4 year, which combined with lower incremental Equivalent Firm Capacity (EFCs) also due to the increased duration-limited capacity, has resulted in step changes in the de-rating factors for those years.

2. Stakeholder Engagement

The modelling analysis has been undertaken by National Grid ESO and has included regular engagement with BEIS, Ofgem and BEIS's PTE throughout the whole process. This extends from agreeing the joint priorities of development projects through to scrutinising the modelling that underpins National Grid ESO's recommendations in the ECR before it is submitted to BEIS by 1 June.

National Grid ESO have also engaged with other industry stakeholders in its role as EMR Delivery Body and in its role of developing the FES assumptions that underpin the modelling. Our stakeholder engagement in our role as EMR Delivery Body includes the annual Capacity Market Launch Event and bilateral meetings. It also includes industry consultations on changes to the methodologies used to calculate technology de-rating factors – as we did this year on potential changes to some embedded generation technologies. We have also continued to produce the interconnector modelling briefing note, which provides an early view of how we intend to carry out the interconnector modelling. It also provides all industry stakeholders an opportunity to provide feedback directly to the PTE for consideration in scrutinising our modelling and their subsequent recommendations.

This year we have also produced a Data Workbook to complement the ECR in response to stakeholder feedback. We hope that this provides easier access to the data in the ECR and welcome feedback on how this could be further improved.

National Grid ESO has a well-established and extensive consultation process to produce the FES – the core supply and demand assumptions that underpin the analysis in the ECR. This operates on an annual basis and includes a launch conference, webinars, workshops and bilateral meetings. This gives opportunity for our stakeholders to provide feedback on our scenarios and share information on the latest market developments. We use this information to help to shape the content of the FES resulting in a set of holistic, credible and plausible scenarios. We publish the FES Stakeholder Feedback Document each year to demonstrate how we have used this feedback to inform our scenarios.

National Grid ESO strives to improve the FES consultation process each year by enhancing engagement activities and finding better ways to record and analyse stakeholder feedback. In developing FES 2022, we engaged with 329 different organisations representing all nine of our stakeholder categories. Of these organisations, 204 were new for FES 2022. The 2022 Stakeholder Feedback Document describes the key changes to this year's scenarios which are expected to be published in the FES 2022 document on 18 July 2022.

We continue to welcome engagement with our stakeholders on our modelling either through email (emrmodelling@nationalgrideso.com), industry forums or bilateral meetings.

3. The Modelling Approach

3.1 High level approach

The modelling approach is guided by the policy and objectives set by Government regarding security of supply. The modelling looks to address the following specific question:

What is the volume of capacity to secure that will be required to meet the security of supply reliability standard of 3 hours Loss of Load Expectation (LOLE)[10]?

Following consultation with BEIS and the PTE, it was agreed that the Dynamic Dispatch Model (DDM)[11] continues to be an appropriate modelling tool to answer this question. This maintains consistency with the energy market modelling work undertaken by BEIS. The DDM has the functionality to model the Capacity Market and produces the same output LOLE values as National Grid ESO's capacity assessment model, when given the same inputs. This provides evidence that its security of supply calculations are robust.

The inputs to the model are in the form of scenarios based on the Future Energy Scenarios (FES)[12] and a Base Case. The scenarios and Base Case are developed to reflect the credible range of uncertainty in future electricity supply and demand. Further details on the scenarios and Base Case can be found in Chapter 4. The main assumptions in the scenarios and Base Case include:

- **Peak demand** – this is the underlying, unrestricted demand in Great Britain, sometimes referred to as consumer demand. 'Underlying demand' is the demand that includes all peak demand in Great Britain, not just that on the transmission system. 'Unrestricted' demand means that no Demand Side Response (DSR) has been subtracted.
- **Generation capacity** – this is the installed capacity of all technologies (including storage) connected to both the transmission and distribution networks.
- **Interconnector capacity** – this is the installed capacity connecting Great Britain to neighbouring markets in Europe. Interconnector flows at peak are calculated in the DDM, so this is not an input assumption.

We also apply a set of sensitivities to the Base Case to assess potential uncertainty that is not covered by the scenarios. Further details on these can be found in Section 4.8.

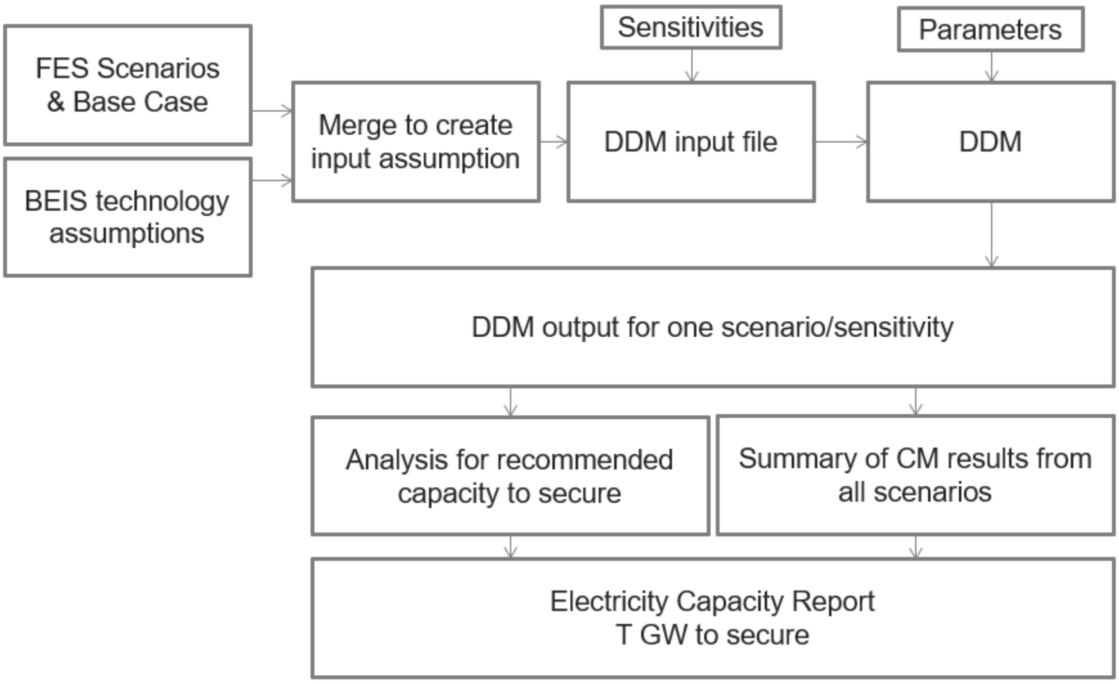
The modelling process is shown in Figure 11. We model a 15-year horizon in the DDM that extends to 2036/37. The modelling process determines both the capacity to secure and the capacity expected to be delivered outside of the Capacity Market for each scenario and sensitivity modelled. The capacity to secure for each of these cases is then considered together to produce a recommended capacity to secure for delivery in 2023/24 T-1 and T-4 for 2026/27. Further details describing this can be found in Annex A.6.

[10] LOLE is the expected number of hours when demand is higher than available generation during the year, before any mitigating / emergency actions are taken but after all system warnings and System Operator (SO) balancing contracts have been exhausted.

[11] DDM Release 6.1.90.0 was used for this analysis

[12] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Figure 11: Process flow chart of approach to calculate target capacity to secure (T) from individual scenario/sensitivity runs



3.2 DDM outputs used in the ECR

The key outputs from the DDM that are used in the ECR are the aggregate capacity values. These outputs are used for all 15 years that are modelled. Specifically, the outputs include:

A. Total de-rated capacity required to meet 3 hours LOLE
B. De-rated capacity to secure in the CM auction
C. De-rated non-eligible capacity expected to be delivered outside the CM auction
D. Total nameplate capacity split by CM and non-CM eligible technologies
E. De-rated capacity already contracted for, from previous auctions (part of C)

Note that A = B + C. Further details on the modelling and aggregate capacities can be found in Annex A.5 and A.6.

In addition to the aggregate capacity values, we also use the expected energy unserved (EEU) and LOLE for the potential de-rated capacity levels in the CM auction for years 2023/24 and 2026/27. These values are used in the LWR calculation to produce the recommended target capacity (T) for each auction. Further details can be found in Chapters 6 and 7.

No other outputs from the DDM are used directly in the ECR.

3.3 High Level Modelling Assumptions

In addition to the Base Case and scenario assumptions described in Chapter 4, the DDM also requires some additional modelling assumptions for the simulations to run. These include assumptions relating to demand, generation, interconnectors and station availability. Further details on these assumptions are explained in this section.

3.3.1 Demand and Generation

The demand and generation assumptions are based on those used in BEIS' modelling[13] (e.g. technology assumptions for generation levelised costs). This forms the basis of our DDM input file. We update some of these assumptions (e.g. annual and peak demands, generation capacities, technologies and start dates) in the DDM input file to match those in the latest FES, Base Case and sensitivities. The key assumptions that have a material impact on the capacity to secure include:

- Demand Forecasts
  - Peak demand (plus reserve for largest infeed loss)
  - Annual demand
- Generation Capacity
  - Capacity eligible for the CM
  - Capacity outside the CM (including capacity secured via previous auctions)
  - Capacities of existing and new interconnectors
- Station availabilities and de-rating factors by technology

The data for these assumptions is provided in Annex A.5.

3.3.2 Interconnectors

Interconnector capacities are based on those in the latest FES and Base Case, which considers both existing and new interconnectors. The latest FES and Base Case capacity assumptions are provided in Section 4.7.

We use a probabilistic distribution of interconnector flows in the DDM to model the contribution of interconnectors to GB at peak times for each scenario and delivery year. The distribution is derived from our pan-European market modelling in BID3[14] and assigns probabilities to different import / export levels for a given net system margin. The DDM combines this distribution with probability distributions for conventional generation, wind and demand to calculate a net system margin distribution. The DDM uses the net system margin distribution to calculate an Equivalent Firm Capacity (EFC) for interconnection. This is used as an estimate of the total de-rated interconnector capacity in that scenario and delivery year for the purpose of calculating the total de-rated capacity required to meet 3 hours LOLE. The interconnection EFC values for the Base Case in the T-1 and T-4 year are provided in Annex A.5.4.

The interconnection EFC can impact the capacity to meet 3 hours LOLE for the T-1 year. This is because the interconnection EFC may differ from the de-rated interconnector

[13] https://www.gov.uk/government/collections/energy-generation-cost-projections
[14] https://afry.com/en/service/bid3-afrys-power-market-modelling-suite

capacity previously contracted in the corresponding T-4 auction. If the interconnection EFC is lower than the previously contracted capacity, then the DDM will treat this as non-delivery and increase the T-1 capacity requirement. If the interconnection EFC is higher than the previously contracted capacity, the surplus is assumed to enter the T-1 auction and so does not impact the T-1 capacity requirement. The interconnection EFC does not impact the T-4 capacity requirement since no interconnectors have been previously contracted.

In addition to this modelling work, National Grid ESO provide modelled ranges of de-rating factors for each connected country participating in the CM auction. See Chapter 5 for more detail around this process and the modelled de-rating factors ranges for each country.

3.3.3 Station Availabilities and De-rating Factors

Conventional generation

Breakdowns and maintenance cycles mean that we assume conventional generation is not available to generate all the time. National Grid ESO calculate the expected availability for each generation type based on its performance during the winter peak period over the last seven years[15]. The DDM uses the availabilities to create a conventional generation distribution on the basis that each unit is assumed to be fully on with a probability equal to its availability and is assumed to be fully off with a probability equal to one minus its availability. The method used to calculate the station availabilities is consistent with the methodology for conventional generation de-rating factors described in Section 2.3.5 of the Capacity Market Rules[16].

The data for the station availability assumptions is provided in Section 5 (CM eligible conventional generation) and Annex A.5.4 (CM ineligible and EFCs for interconnectors, storage, solar and wind).

Intermittent renewable generation

Intermittent renewable plants such as wind and solar are assumed to run whenever they have an available source of energy (e.g. the wind is blowing or the sun is shining). We assess their expected contribution to security of supply by calculating their EFC for the entire winter period.

The wind EFC is calculated using historical data of observed wind speeds across Great Britain. We use wind power curves to convert wind speeds into wind output generation, which is used to determine the EFC, which is defined as the level of 100% reliable (firm) plant that could replace the entire wind fleet and provide the same contribution to security of supply.

The wind EFC depends on the amount of installed wind capacity, its geographical location and the amount of wind that might be expected at times of high demand. It also depends on how tight the overall system is. If the system is tighter, there are more periods in which wind generation is preventing loss of load rather than displacing other types of generation in the merit order, and so the EFC is higher. The wind EFC is not an assumption or

[15] Specifically, these periods are 0700-1900 Monday-Friday, December-February (inclusive) on days with a peak demand greater than the 50th percentile (90th percentile for CCGTs) of peak demands for that winter
[16] https://www.gov.uk/government/publications/capacity-market-rules

prediction of wind output at peak times and should not be treated as such. The wind EFC is calculated by the DDM and is therefore an output of our modelling. The wind EFC values for the Base Case are provided in Annex A.5.4.

Solar PV can make a small contribution to security of supply, particularly if storage capacity is installed. This was evident from a previous development project reported in the 2019 ECR. A related project also reviewed the de-rating factors used for solar (and storage) in the DDM so that the total (storage + wind + solar) fleet de-rated capacity in the DDM aligned to the combined (storage / wind / solar) fleet EFC calculated in the development project. The solar fleet EFC in the DDM is calculated this way using updated estimates (see Annex A.5.4). Please refer to Section 2.5.2 in the 2019 ECR for further details on these projects[17].

We note that the wind and solar EFCs used in the DDM to determine the auction target capacity are different to the recommended auction de-rating factors. This is because the EFC values used in the DDM include the contribution from the entire wind and solar fleet. The de-rating factors for the auction are based on incremental EFCs for wind and solar, which represents the contribution to security of supply brought by delivering any additional wind and solar via the Capacity Market.

Impact of availability assumptions

Given that the recommended capacity to secure is a de-rated value, the assumptions around the availability of eligible technologies have a limited impact on the capacity required in the T-4 runs[18]. For the T-1 runs, changes to eligible technology availability assumptions may have an impact on the contribution of capacity contracted in previous auctions, which we account for in the low and high availability sensitivities. However, such changes have a limited impact on our recommendation for the T-1 year as the low and high availability sensitivities do not set the extremes of the LWR range. For ineligible capacity (such as those outlined in Reg. 16 of the Electricity Capacity Regulations), changes in availability assumptions may have an impact on our recommendations as the ineligible capacity is netted off the target, but such impacts are usually small as year-on-year changes in these availability assumptions are small and the ineligible capacity is a relatively small proportion of the total capacity required to meet 3 hours LOLE.

3.4 Development projects

We undertake development projects each year to enhance the ECR modelling. The development projects are intended to address recommendations from the PTE in their annual report and any other areas where the modelling could be improved. This also includes updating/refreshing existing data sources, integrating the latest versions of the models, and improving efficiency in our modelling processes. The development projects taken forward each year are selected from a prioritisation process involving National Grid ESO, BEIS, the PTE and Ofgem. National Grid ESO then deliver the development projects between September and February, which includes regular engagement with BEIS, Ofgem and the PTE, who consider whether the outputs of the projects have been delivered and are appropriate to be included in the ECR modelling.

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[17] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf
[18] Broadly the same level of de-rated capacity is required to hit the 3 hours LOLE target, although the name-plate capacity required to achieve that level of de-rated capacity will be slightly different

3.4.1 Process for selecting which development projects to progress

The prioritisation for the 2021/22 development projects followed the same process as last year. Each project was ranked independently by National Grid ESO, BEIS, Ofgem and the PTE considering factors such as its potential impact on our recommendations, the effort required and how urgent it was deemed to be. The prioritisation process also considers the potential complexity of the project and whether sufficient data is available to deliver the intended output. Scoring across these formats were totalled to give ranking to each project. All rankings were then combined to give a single prioritised list reflecting the views of all four parties. The highest priority projects were then taken forward.

3.4.2 Key projects undertaken

In their 2021 report[19], the PTE made eight new recommendations numbered 58 to 65, summarised in Table 2.

Table 2: New PTE recommendations - project summary

#	Summary	Outcome
58	Range of short-term demand uncertainty	Described below
59	Factors affecting peak demand and stress period behaviour	Described below
60	Non-delivery sensitivities	Described below
61	Empirical analysis of past non-delivery	Described below
62	Timing of CM activities	This recommendation does not relate to modelling and needs to be considered by BEIS and Ofgem.
63	Turn-down DSR duration limits	At the moment, we are not aware of any data sets that are readily available to assess this, and so we intend to explore other potential options with BEIS, Ofgem and the PTE.
64	Interconnector de-rating consistency	Not progressed this year
65	European DSR and embedded resources availability	Chapter 5 sets out that we have updated our European scenario assumptions, although there is little evidence on the availability of DSR and embedded resources

Annex A.3 contains a list of all the development projects considered and which ones were progressed based on the prioritisation scoring. A summary of the key development projects taken forward this year is included below.

19 https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/999459/panel-technical-experts-report-on-2021-electricity-capacity-report.pdf

ESO Demand Modelling

The Base Case peak demand forecast is one of the most important assumptions that impacts the recommended auction targets. As such there has been a lot of focus on this in recent years, reflected in recommendations from the PTE in their annual reports and the enhancements we have made to improve this area of our modelling. This is a complex area of modelling that is continually evolving. We have engaged regularly with the PTE on this during the last year and expect to implement further enhancements in the coming years to address previous PTE recommendations, including recommendation 59 in the 2021 PTE report.

This year we have also started work to assess the uncertainty around the Base Case peak demand in response to recommendation 58 in the 2021 PTE report. This has led to the first estimate of this uncertainty based on the ratio of annual to peak demand and losses. We believe that this represents a positive first step in trying to better quantify this uncertainty and will allow us to build on this in the coming years. As such, we have decided to model the high / low demand sensitivities based on this uncertainty.

Non-delivery

In response to recommendations 60 and 61 in the 2021 PTE report, we have undertaken two projects to examine how we assess uncertainty in future non-delivery. This was also motivated by our change of approach in the 2021 ECR and the subsequent impact that had on the recommended target capacity for the auctions.

Our Base Case assumptions in the ECR do not currently reflect the uncertainty of future non-delivery that is not yet known to us. Any non-delivery in the Base Case is solely attributed to either capacity that has terminated its CM agreement or market intelligence tells us that a capacity provider won't be able to meet its existing CM obligations. Uncertainty of future non-delivery that may only become apparent later on is reflected through the non-delivery sensitivities. In the 2021 ECR, we presented evidence based on recent observations that the way we were constructing the non-delivery sensitivities was significantly underestimating the potential risks.

i) Analysis of past non-delivery

We have now carried out a thorough assessment of past non-delivery in the CM. This considered different types of non-delivery and when we knew that capacity was not going to be delivered. This means we could reflect this lack of capacity in our recommendations. We also considered market response from interconnectors during tight periods.

The analysis of past non-delivery showed that we can be almost certain that some non-delivery (e.g. unplanned outages covering the whole winter) will materialise after we have made our recommendations (including the adjustment to the Demand Curve after prequalification), and so is a risk that we need to continue to mitigate against. The amount of non-delivery varied significantly from one delivery year to the next (see Table 26).We estimate that on average there has been about 2.5 GW of non-delivery that has only become apparent after the T-1 auction for that delivery year. This even allows for market response and would be even higher had it not been for exceptionally low levels in the first CM delivery year in 2017/18. The highest level of non-delivery exceeded over 6 GW for winter 2020/21 – again, allowing for market response – and wasn't apparent until after the T-1 auction for that delivery year. Our analysis shows that there is even more uncertainty in the amount of non-delivery that occurs after our T-4 recommendation, with nearly 7 GW on average. While we have an opportunity to adjust for this at the T-1 auction, we should be mindful of the impact this potentially has in increasing the T-1 auction target, as evident in both the 2021 and 2022 ECRs.

We believe that this evidence further supports the changes we made to the non-delivery sensitivities last year, which we will continue to use in this ECR. Further details of the past non-delivery analysis can be found in the Annex A.6.1.

ii) Modelling uncertainty of future non-delivery

Motivated by our analysis of past non-delivery, we commissioned our academic consultants to explore alternative ways of modelling this uncertainty within the Base Case LOLE calculation. The main outcomes of this work were that the uncertainty of future non-delivery can be modelled probabilistically in the Base Case. They proposed that modest levels of non-delivery (e.g. similar to past levels) could be modelled by adjusting the station availabilities currently used in the LOLE calculation with a non-delivery probability. In addition, they proposed that additional supplementary analysis could be performed to assess the impact of more extreme non-delivery, which may help decision makers understand the actions needed to mitigate more severe risks even if these cases weren't used in the actual decision-making process.

This work was concluded in March 2022 and as any implementation requires changes to the DDM, we have not implemented their recommendations this year. Instead, we will take forward a development project next year to do this and continue to use the method used in last year's ECR to reflect uncertainty of future non-delivery this year.

Embedded Generation De-rating Factors

We ran an industry consultation on potential changes to de-rating factors for some embedded technologies in early 2022[20]. The objective was to consult with stakeholders on whether it would be more appropriate to calculate de-rating factors directly from recently acquired embedded generation data, rather than continuing to infer de-rating factors from transmission-based technologies. This followed on from work reported in the 2021 ECR in response to recommendation 53 in the 2020 PTE report.

We published our response to the consultation on 11 March 2022[21]. While we believed there was merit in consulting on an alternative approach using the new data available, there were concerns on not being able to use metered generation output to represent asset availability in a sufficiently robust way. As such, we have not implemented any changes to the de-rating factor methodology for these embedded generation technologies at the present time. We continue to believe that improving this area of our modelling is in the interest of consumers. Therefore, as indicated in our consultation, we are now intending to explore how we can work with industry stakeholders to obtain data that better reflects the availability of embedded generation assets. This will help us to calculate de-rating factors for embedded generation technologies directly from embedded generation data.

[20] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Industry%20Consultation%20-%20De-rating%20Factor%20Methodology%20for%20Embedded%20Generation%20Technologies%20v1.0.pdf
[21] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Embedded%20generation%20de-rating%20consultation%20response%20document.pdf

Interconnector modelling

Our pan-European market modelling to recommend de-rating factor ranges for interconnected countries remains one of the more challenging aspects of our modelling, in that it is a complex area of modelling with significant uncertainty. Each year we have sought to improve this aspect of our modelling, and once again, published a briefing note[22] ahead of the 2022 ECR to highlight some of the developments and invite stakeholder feedback.

While our approach remains broadly similar to last year, we have undertaken projects to refresh the underlying supply and demand assumptions in our European scenarios and to enhance the functionality of our pan-European market model, BID3, to provide greater insight on our modelling.

In the 2021 ECR, our assumptions for Europe were based on a data set that we procured from Afry. This meant that we represented Europe with a single scenario. Since last year, we have worked with Afry to develop two bespoke European scenarios as part of our Future Energy Scenarios (FES). We believe that this represents a significant step forward from last year because:

a) our European scenarios are now consistent with the latest European policy on net zero;
b) they have been designed to align with the Consumer Transformation and System Transformation scenarios for Great Britain, which meet net zero in our FES; and
c) we should be able to share more details of the scenario assumptions to improve transparency with our stakeholders, which we weren't able to do last year. Initially we intend to publish capacity by technology and demand for European countries. These will be published as part of the FES data workbook which will be hosted in the FES area of the ESO website in July 2022.[23]

The European scenario assumptions also include an extra weather year, such that we now have a 35-year history covering 1985 – 2019, helping us capture even more variety in weather patterns across Europe and further improve the robustness of the modelling. Our European scenarios were developed before the invasion of Ukraine. As such, they will not reflect the potential uncertainty on energy security and any subsequent changes in the market outlook, which we have considered through some sensitivity analysis in Chapter 5.

We have also worked with Afry to develop new functionality in the BID3 model. We use a dedicated 'LOLE' module in BID3 to assess the potential imports from interconnectors when there is a stress event in Great Britain. The imports are calculated as an average over 1000 different outage patterns and around 100 tight periods (the exact number is consistent with 3 hours/year LOLE * number of historical weather years in our modelling) for each scenario and sensitivity modelled. The new functionality allows us to assess the distribution from which this average is calculated. We can do this by calculating the interconnector flows for different percentiles. We think this is helpful because it will provide further insight on risk that a simple average cannot show (e.g. how often imports could drop to zero as a stress event occurs simultaneously in Europe), that will help decision-makers understand the impact of the decisions they take.

[22] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Modelling%20de-rating%20factors%20for%20interconnected%20countries%20in%20the%202022%20ECR.pdf
[23] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Adverse weather scenarios

Our current modelling relies on using historical demand and wind data to assess the uncertainty of future weather patterns. We currently use a 16-year history, which is relatively short and may not be representative of future weather patterns that could occur. The Met Office and National Infrastructure Commision have undertaken a project to produce data sets to assess the impact on the energy systems from adverse weather patterns that are statistically possible but have not previously happened.[24] We have explored how we could use these data sets in our modelling. While they represent an encouraging step forward, the current granularity of daily resolution rather than hourly resolution means that we cannot use this data in its current form. We will continue to support further work on this with the Met Office that will hopefully lead to data sets with appropriate granularity for use in our modelling.

3.5 Modelling Enhancements since Last Report

In addition to the previously described development projects, we have also updated our historical wind and demand data by an additional 3 years, meaning we now have a 16-year history in the LOLE calculations. We have also taken steps to enhance automation in our modelling processes to improve efficiency and reduce potential errors arising from manual process steps. This also involved updating to the latest version of DDM (version 6.1.90.0).

3.6 Quality Assurance

When undertaking any analysis, National Grid ESO looks to ensure that a robust Quality Assurance (QA) process has been implemented. National Grid ESO has previously worked closely with BEIS' Modelling Integrity team to ensure that the QA process is closely aligned to BEIS' in-house QA process. In addition, the PTE carries out a sense check on the modelling input assumptions, reviews the results and reports on the overall process. Within National Grid ESO, the process has governance under the Director UK Electricity System Operator.

Further details of the QA checks are included in Annex A.10.

[24] https://catalogue.ceda.ac.uk/uuid/7beeed0bc7fa41feb10be22ee9d10f00

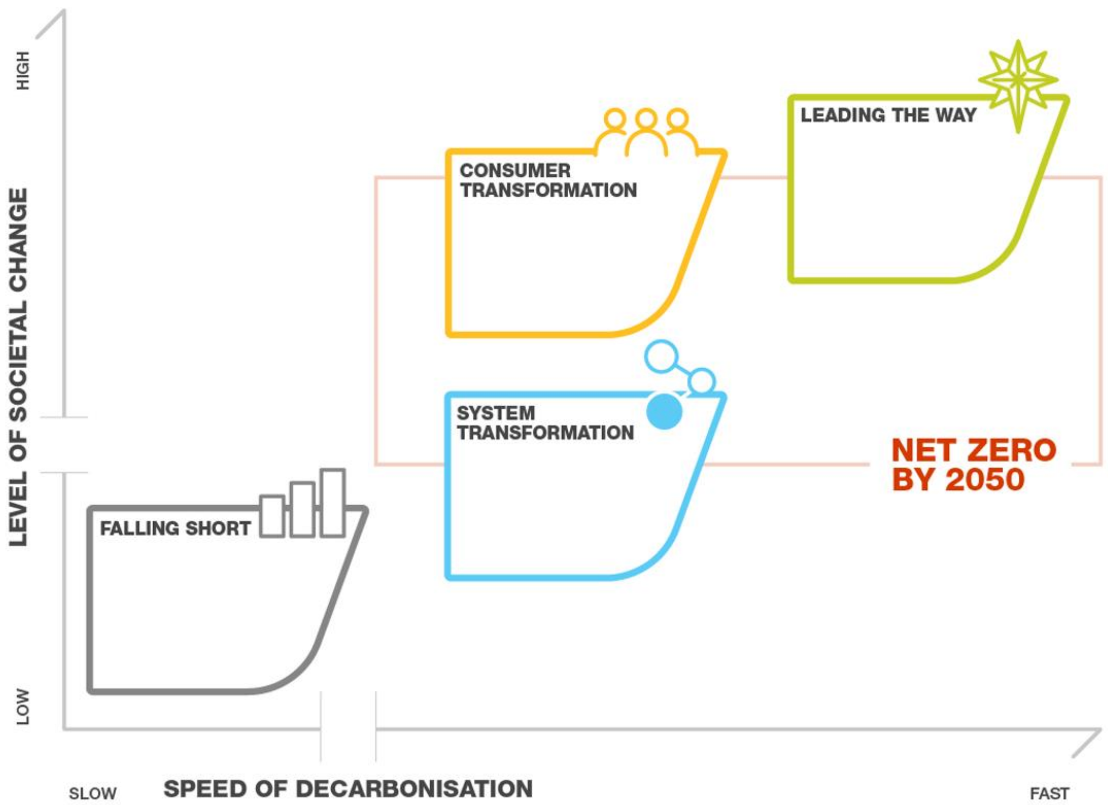
4. Scenarios & Sensitivities

4.1 Overview

National Grid ESO has a well-established process to develop scenarios that reflect the uncertain supply and demand pathways on the future of energy in Great Britain. These scenarios are published annually in National Grid ESO's Future Energy Scenarios (FES) [25]. The scenarios consider the key challenges for the energy sector in meeting decarbonisation targets by 2050. The supply and demand assumptions developed in the FES are used for several ESO activities. These include network development (Electricity Ten Year Statement[26], Network Options Assessment[27]), operability (System Operability Framework [28]) and security of supply (ECR, Winter Outlook Report[29] and Summer Outlook Report[30]).

The FES 2022 scenario framework has been designed to explore the most fundamental drivers of uncertainty in the future energy landscape and is shown in Figure 12.

Figure 12: FES 2022 Scenario Framework



[25] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[26] https://www.nationalgrideso.com/research-publications/etys
[27] https://www.nationalgrideso.com/research-publications/network-options-assessment-noa
[28] https://www.nationalgrideso.com/research-publications/system-operability-framework-sof
[29] https://www.nationalgrideso.com/research-publications/winter-outlook
[30] https://www.nationalgrideso.com/research-publications/summer-outlook

For FES 2022, we are retaining the same scenarios and framework as used in FES 2020 and FES 2021, as we believe they are still fit for purpose. Within our FES 2022 Call for Evidence, we asked stakeholders if they were happy for us to retain the same scenario framework for FES 2022. Most respondents supported retaining the scenarios for FES 2022 with year-on-year consistency being highly valued. This means we have retained both the *speed of decarbonisation* axis and the *level of societal change* axis.

We have however, after listening to stakeholders through our engagement activities, decided to change the name of the Steady Progression scenario to Falling Short. Some stakeholders felt it wasn't sufficiently clear from the old name that this scenario did not meet the Net Zero target. We believe that this new name more accurately reflects the intent of the scenario. This is just a name change and Falling Short will perform the same role as Steady Progression in the FES framework (i.e. it represents the credible slowest progress towards decarbonisation).[31]

We have modelled four scenarios; three which meet or exceed the net zero target and one which does not. Two of our scenarios meet the target in 2050: System Transformation, which focuses on supply side decarbonisation, and Consumer Transformation, which relies on more significant changes in society and how consumers use energy. Falling Short does not meet the target, while Leading the Way meets the target before 2050 and requires the highest levels of societal change.

The scenarios will continue to reflect a mix of technology options, taking account of the rapid changes in the energy industry, markets and consumer behaviour. Security of supply for both gas and electricity continue to be met in all scenarios for FES 2022.

For the purposes of modelling scenarios for the Capacity Market, BEIS's DDM model has been used, as described in both Chapter 3 and the Annex A.6. Thus, while the non-Capacity Market technologies are fixed to the levels assumed in each of the FES scenarios, the DDM calculates CM qualified capacity to ensure that the 3 hours LOLE Reliability Standard is met. Hence the capacities shown in this analysis may diverge from those in the original FES scenarios, and reflect what has actually happened in the market post auctions, incorporating any potential for over-delivery rather than the theoretical recommended target capacity.

4.1.1 Base Case

In addition to the four FES scenarios, we have used a Base Case known as the 'Five-Year Forecast' to 2026/27, against which all the sensitivities will be run. This case follows the same principles and modelling approach as the main scenarios to give a five-year demand and generation background that represents our best view and is typically within the FES scenario range. Due to the inherent uncertainty across the market beyond 2026/27, we do not produce a forecast beyond the next five years. Instead, the Base Case follows the FES scenario that is closest in peak demand to provide a 15-year view in the ECR. In FES 2022, the Base Case is closest to the System Transformation scenario and so we have aligned the Base Case to this scenario from 2027/28 onwards in our ECR analysis.

[31] This change of name doesn't change anything else about the scenario and its placement within the framework where it continues to represent the credible slowest progress towards decarbonisation.

The Base Case takes account of Capacity Market units awarded agreements in previous auctions that are now known not to be able to honour their contracts due to those agreements being terminated. Additional non-delivery may also be assumed in the Base Case based on our best view from market intelligence of capacity providers that are not currently expected to meet their obligations.

Energy demand

Demand reduction and decarbonisation continues at a steady pace due to economic, political and social focus elsewhere. In the Industrial & Commercial (I&C) sectors, the overall economic growth forecast used in the modelling is based on Oxford Economics projections and benchmarked to the latest Office for Budget Responsibility report. The impact from COVID-19 reduces short term electricity demand. Demand in these sectors is heavily influenced by the size of the economy in the UK, which is assumed to have a fairly close trading relationship with the EU. The UK economy is forecast to expand slowly but demand is offset by policy, incentivising slow improvements in energy efficiency. Residential demands are based on the 'Oxford Economics' housing base view, central regression of 'Energy Consumption in the UK' data for appliances and energy efficiency, and inclusion of EU halogen lighting policy. Residential light demand falls rapidly with the policy driven phase-out of inefficient bulbs, and all other residential appliance demands fall at slow historical rates.

Transport

Electric cars increase in popularity for consumers as battery prices fall, range increases and more models become available on the market. We have seen continued acceleration in the growth of sales of battery electric cars and vans in 2021, broadly in line with expected projections in FES 2021. For commercial road transport, electricity and natural gas increase in prevalence as emissions reduction and decarbonisation continues. In the transport sector, projections are based upon a diffusion model to calculate the proportion of the potential market that adopts the technology at a given time based upon total cost of ownership in relation to the current dominant technology. This is done for motorbikes, cars, light goods vehicles (vans), heavy goods vehicles (HGVs) and buses & coaches; cars are further split down into compact, mid-sized and large segments.

Heat

The next five years will see slow but steady progress towards decarbonisation of heat, through uptake of lower carbon technologies and thermal efficiency improvements, mainly via improved gas boiler standards (e.g. Boiler Plus in England) and better home insulation. Base Case assumptions for fuel prices, technology costs, and available tariffs have been used to determine the marginal cost benefits of switching to low-carbon heating. Heat networks will continue their recent strong growth through continuing support from the Heat Networks Investment Project funding programme, although most schemes will continue to be powered by gas CHPs. Gas demand for heat will remain stable or decline slightly over this period whilst electricity demand for heating will see a small increase.

This year we have refined our new spatial heat model that outputs results with greater granularity on a regional level[32]. The new model is intended to enhance our understanding

[32] https://www.nationalgrideso.com/document/190471/download

of the potential decarbonisation routes, their likelihood, and the impact of these on networks as well as on consumers.

Electricity supply

For electricity supply, the five-year forecast represents our best view of the generation that we expect to be operational. This includes generation connected to the transmission and distribution networks, as well as interconnectors and storage. This is based on a combination of market intelligence[33] and economic modelling. In most cases, we would expect generation to deliver in line with Capacity Market agreements and Contracts for Difference, although we make some allowance for non-delivery, dependent on market intelligence. The four scenarios then consider some of the uncertainties around this view. For example, this may include power stations closing early or staying open longer than expected; new projects being delivered ahead of schedule or delayed. These assumptions vary across the scenarios in line with the FES Scenario Framework.

Gas supply

Global gas flows will remain subject to weather, market and political drivers over the next five years. The conflict in Ukraine has incentivised maximising production from the UKCS to help minimise the impact of global gas price rises, with competition for imports as a result of the conflict expected to be more fierce than usual. The Government's energy security strategy sets out an aim to maximise production from UK Continental Shelf (UKCS).

4.2 Scenario Descriptions

Descriptions of the four scenarios in FES can be obtained from FES 2022[34] which is expected to be published on 18 July 2022. Details of some of the key assumptions in the scenarios that are most relevant to our modelling are included in the subsequent charts in the rest of Chapter 4.

4.3 Demand Forecast

The definition of peak demand used in the modelling is Unrestricted GB National Demand[35], plus demand supplied by distributed generation. Reserve required to cover for the single largest infeed loss is not included in the demand definition but is included in the modelling. Demand is based on the Average Cold Spell[36] (ACS) peak demand and is consistently applied within the sensitivities applied to the Base Case. The only adjustments to ACS peak demand are for the high and low demand sensitivities.

As the peak demand forecast used in the Capacity Market reflects total GB consumer demand (sometimes referred to as underlying demand), demand side response (DSR) including Triad avoidance is less relevant from demand perspective. While this is important

[33] e.g. press releases / announcements, TEC register, embedded generation register, interconnector register, information from bilateral meetings with generators and/or project developers
[34] https://www.nationalgrideso.com/future-energy/future-energy-scenarios
[35] National demand is defined in the Grid Code 'Glossary and Definitions' https://www.nationalgrideso.com/codes/grid-code?code-documents=
[36] The Average Cold Spell (ACS) peak demand is the demand level resulting from a particular combination of weather elements that give rise to a level of peak demand within a financial year (1 April to 31 March) that has a 50% chance of being exceeded as a result of weather variations alone. The Annual ACS Conditions are defined in the Grid Code.

in terms of how National Grid ESO operates the system since it reflects the demand on the transmission system, DSR and Triad avoidance is considered as supply in the CM since it participates in the auction.

There are four main demand areas that are modelled:

- Industrial & Commercial (excluding heat and transport)
- Residential (excluding heat and transport)
- Heat
- Road transport

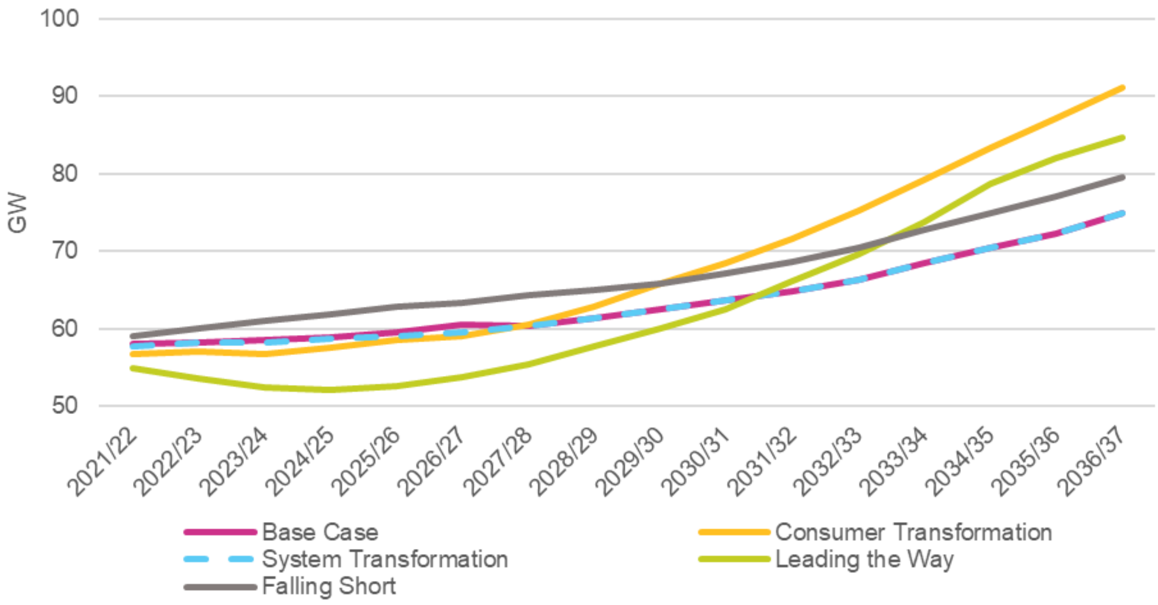
Industrial and commercial demand is based on current views of energy policy and the latest 'Oxford Economics' baseline economic and price forecasts at the time of scenario creation. Residential demand comprises the other component of peak and takes into account energy policy, consumer behaviour and uptake of new technologies such as LED lighting and heat pump white goods. Heat is based on a new model which considers location, housing types, thermal efficiency, energy policy, technology types and consumer adoption rates. Road transport considers energy policy, efficiency, consumer choice and uptake rates.

The starting point for our demand forecast projections is the out-turn for the most recent winter. In our peak demand forecasts for the Base Case and FES 2022 scenarios we assume no peak demand suppression due to COVID-19 within our forecasts. Peak demands in the near term are similar to FES 2021, with no major changes impacting demand forecasts across this time horizon. More rapid electrification of heat and transport starts to have an impact to increase peak demands in the mid-2020s. We observed an increase in National Demand for the winter 2021/22 compared to forecasts. We hypothesise that this is due to a reduction on electricity output from embedded generation, therefore not impacting the analysis for the total underlying demand. This hypothesis is being tested using metered data from distributed generators and we will keep BEIS informed of progress with this analysis.

There is lower demand forecast for Leading the Way scenario compared to last year which is mostly due to an update to the assumptions for Electric Vehicles and Heating. For electric vehicles we assume for FES 2022 an earlier adoption of time-of-use tariffs for owners of electric vehicles which reduces peak charging demand by up to 2GW in the mid-2020s. For heating we assume for FES 2022 fewer hybrid heat pumps with electric resistive heating, as this is an output of our new heat model that looks at cost optimisation. This reduces demand by up to 1GW in the mid-2020s. For heating we also assume for FES 2022 an increase in district heating which has a high level of peak-avoidance. This reduces demand by up to 1GW in the mid-2020s. Other smaller changes in modelling make up the remainder of differences in peak electricity demand between FES 2021 and FES 2022 for the Leading the Way scenario.

Figure 13 shows the peak demands for the Base Case and the FES scenarios over the next 15 years.

Figure 13: Peak Demand - FES Scenarios and Base Case to 2036/37



In May 2019, the UK Government amended the 2008 Climate Change Act, changing the 80% greenhouse gas reduction target to 'net zero emissions'. We consulted with the energy industry and stakeholders on draft scenarios and used feedback to finalise and refine the 2022 projections. Three of the four scenarios achieve net zero emissions by 2050. In these scenarios, all sectors of UK society are decarbonised as much as possible by 2050. Electrification of heat and transport, the requirement to substitute almost all fossil fuels, along with population growth result in increased demands. This is offset by energy efficiency, fuel prices or fuel substitution for hydrogen in System Transformation.

After the mid-2020s, demand is expected to increase due to adoption of electrified road transport and electrified, low carbon heat. Key uncertainties are the levels of 'smart' energy use to reduce system peak (particularly from electric vehicle charging and heat storage),the speed of adoption of these and the rate at which industrial fuel switching away from fossil fuels takes place.

Electricity demand continues to increase, even more so than in FES 2021. Accelerated industrial fuel switching including electrification increases electricity demand for both peak and annual demands in the industrial sector. New demand from data centres is captured in our modelling this year, increasing commercial electricity demands at both annual and peak. Transport demands are affected by greater electrification of HGVs through the 2030s, particularly in Consumer Transformation and Leading the Way. Residential and commercial premises also see more rapid heat pump adoption in these scenarios increasing electricity demand. Please refer to Annex A.1 for details on the demand assumptions used in the FES scenarios.

4.4 Generation Capacity

Our generation capacity assumptions from 2021/22 to 2026/27 are based on the latest market intelligence and an economic assessment, providing a potential view of the generation background over the next five years.

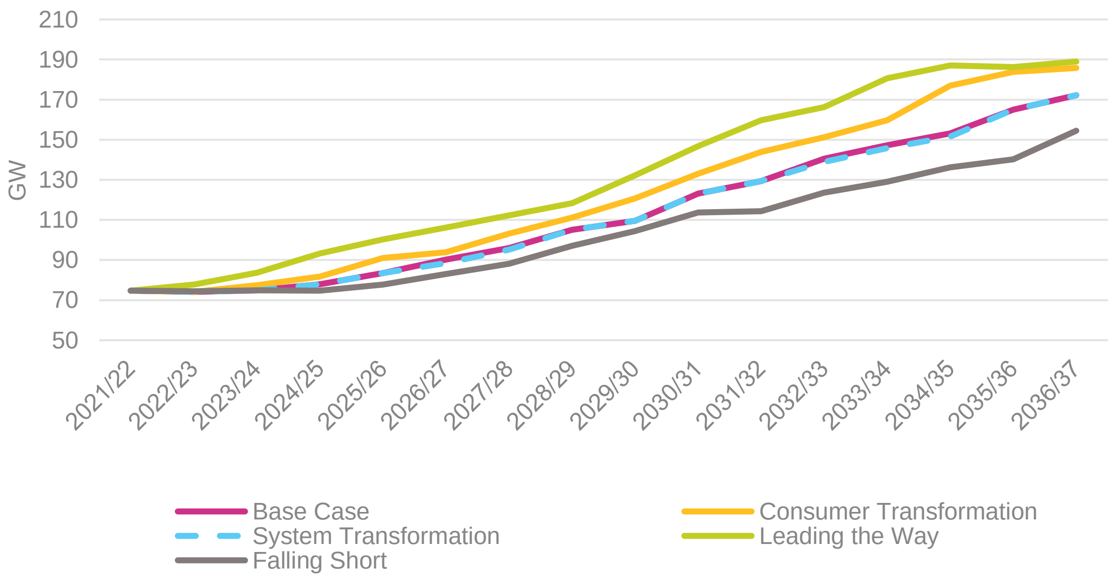
We assume that the price of the new UK Emissions Trading Scheme (ETS) will be similar to the EU ETS and that the two will continue on a similar trajectory out to 2050. The GB Carbon Price Support is assumed to continue in line with Budget announcements before gradually being phased out as the ETS increases.

We consider the impact of the Industrial Emissions Directive (IED) on both large plant (via the EU's Large Combustion Plant Directive) and medium plant (via the Medium Combustion Plant Directive (MCPD)) and the more onerous rules applied by Department for the Environment, Food and Rural Affairs (DEFRA). For large plant, we consider the impact on a case-by-case basis as the option that each generator took has an impact on the expected running hours and closure date. For example, those plant that entered into the Limited Life Derogation (LLD) can run for no more than 17,500 hours starting on 1 January 2016 and ending no later than 31 December 2023.

Like with large plant, the emission limits for medium plant depend on numerous factors including the build date and whether the plant was awarded contracts in the 2014 or 2015 capacity auctions. The greatest impact is on the diesel reciprocating engines. Following stakeholder engagement, we assume there will be a transition away from diesel reciprocating engines because of the emissions directive and the general market conditions.

Figure 14 shows the transmission connected generation capacity assumed over the next 15 years.

Figure 14: FES 2022 transmission connected nameplate capacity to 2036/37



After 2026/27, each of the FES scenarios has a generation background that is based on the underlying scenario assumptions. These generation backgrounds include varying amounts of renewable / low carbon capacity, and differing volumes of Capacity Market eligible plant. The data in this section was taken from a near final version of the FES. Since then, the FES generation assumption from 2027/28 onwards have been revised slightly.

Capacity Market eligibility

Any generation capacity which is currently receiving, or will receive, support under the following initiatives is not eligible for the Capacity Market:

- Contracts for Difference (CfD)
- Final Investment Decision Enabling Regime (FIDeR)
- Feed in Tariffs (FiT)
- Renewables Obligation (RO) (now closed to new applications, but some capacity will continue to receive support).

However, once a plant stops receiving support under these schemes, it will become eligible for the Capacity Market (assuming the CM rules allow it to participate).

Any generation capacity that is under a total capacity of 1 MW is assumed not to be eligible for the Capacity Market in this modelling – although any plant under 1 MW not receiving support from the above schemes can enter the auction if combined with other capacity by an aggregator. This latter group is estimated to range from 0.3 to 0.6 GW over the period to 2026/27 depending on the FES scenario and year and includes some onsite autogeneration above 1 MW assumed to opt out of the Capacity Market. Note that small scale renewable technologies are assumed to receive FiT support and therefore are excluded from this range.

Lastly, any capacity that is receiving a Capacity Market Agreement for longer than one year will not be eligible for successive auctions until its existing CM Agreement(s) end.

Assumptions

Barring these exceptions based on size and support mechanism, all other forms of generation capacity are eligible for the Capacity Market. For the purposes of our modelling, we assume that:

- All eligible capacity assumed in each scenario will enter the Capacity Market and
- No capacity will opt-out and remain operational.

However, we recognise that with an aging fleet of power stations these assumptions are unlikely to hold true. Therefore, the recommended capacity to secure will be adjusted to account for known opted-out plants following the pre-qualification process.

The focus of the modelling is to estimate the total eligible de-rated capacity that needs to be secured in order to achieve a reliability standard of 3 hours LOLE or lower. The final mix of generation technologies that make up this total capacity will be decided by the capacity auction and is not predetermined as a result of the modelling.

The Data Workbook (Figure 42 worksheet) contains a breakdown of generation that is eligible and not eligible for the CM. Further details of the underlying generation assumptions, including the technology mix, will be available when the FES 2022 document is published in week commencing 18 July 2022[37].

4.5 Distributed Generation

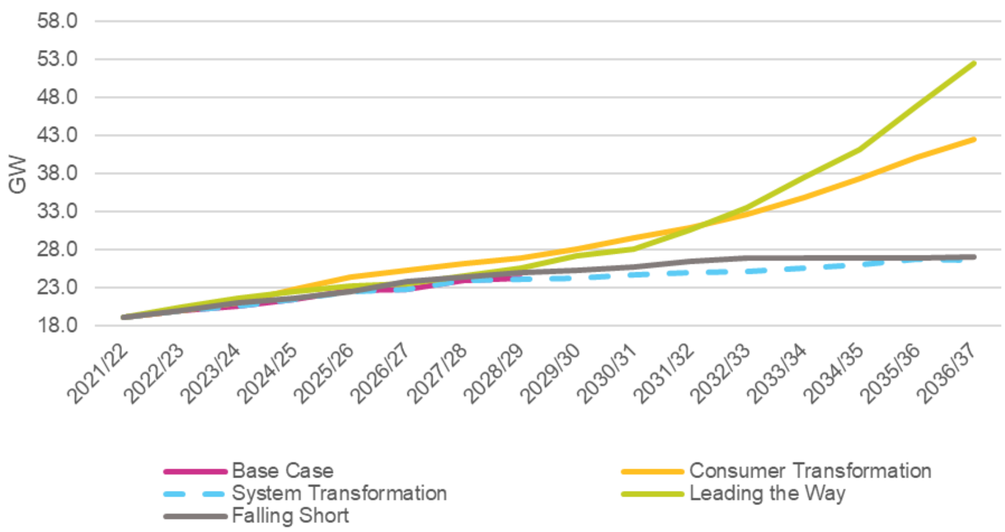
The scenario projections for distributed generation (generation which is connected to the lower voltage distribution networks) considers which plant is currently operating, and which plant may close and open in the future.

The scenarios consider around 30 different existing technologies, as well as considering new types of generation that may connect in the future. The contribution of each of these technologies to peak demand is also taken into account – so for example, solar is excluded from these projections, due to the assumption that it is unable to contribute to peak demand, which currently takes place in the hours of darkness[38].

A variety of data sources[39] are used to develop a list of projects for existing generation above 1 MW in size. We are continually seeking to improve the data available, as well as our analysis, to have an improved picture of how distributed generation operates over the year. This will help us to improve our understanding of how small-scale plant contributes to demand across the seasons.

Figure 15 shows nameplate capacities (excluding solar) for distributed generation out to 2036/37.

Figure 15: Distributed generation nameplate capacity (excluding solar) to 2036/37



[37] The ECR 2022 modelling was carried out using the FES assumptions that were provided on 19 April 2022. Since then, some small changes have been made, particularly to assumptions in later years, which do not impact our recommendations. However, this may result in an apparent discrepancy between the FES data included in the 2022 ECR and that published in FES 2022 (available July 2022)
[38] The de-rating factor for solar is less than 6% for CM auctions
[39] For example, Renewable Energy Planning Database, CM register, DNO long term development statement and others

4.6 Demand Side Response

In the FES, demand side response (DSR) has been defined as a deliberate change to an end user's natural pattern of metered electricity consumption brought about by a signal from another party. That is, demand shifting or demand reduction and not the use of generators to substitute the supply source. So, for instance, Triad avoidance is made up of both demand reduction and switching to an alternative supply source (which is included in the distribution connected generation technologies). Within our definition of DSR, we consider only the demand reduction element.

Observed Triad avoidance in winter 2019/20 was 2.4 GW. In winter 2020/21, this reduced to 1.7 GW and in winter 2021/22 it further reduced to 1.3 GW. It is believed this is a market response to changes in the charging regime, which has changed the value of generating at the time of transmission peak demand.

Domestic Peak Response

We believe there are three other factors which must work in tandem to give the most flexibility at the lowest cost to consumers. These are:

Smart Meters: These only have a short-lived behavioural impact by themselves. Crucially they enable robust adoption of time of use tariffs (TOUTs), which potentially have wider benefits across the energy system. Their impact is enhanced where they are supported by appropriate marketing and education around energy use.

Smart Technology: These are appliances that have two-way communication capability and interact with the consumer and other parties; for instance, Hive or Nest. As the technology improves, service providers such as aggregators have a greater role to play.

Smart Pricing: The appropriate use of TOUTs incentivises consumers to move those energy demanding activities to off peak times where possible. The more engaged consumers, energy suppliers and government are, the greater the impact of TOUTs.

Industrial and Commercial DSR

Although there is uncertainty over the projected levels of industrial and commercial DSR, it should be noted that the DSR assumptions do not directly impact the recommended capacity to secure since we use unrestricted peak demand in our modelling (see Section 3.1). Furthermore, in the capacity auctions, DSR competes with other types of new / existing eligible capacity to meet the capacity requirement.

The chart in Figure 16 shows the industrial and commercial DSR for the scenarios to 2036/37. There is uncertainty in the range of projections in the next 5 years. On the upside, for the next ten to fifteen years, in all the scenarios, there is a growth and development in the enabling systems, such as information communications technology, which permit DSR to evolve. There is still uncertainty around the impact of the 2019 Targeted Charging Review[40] demand for residual reforms which were implemented in April 2022 and change charging arrangements for use and access to the GB transmission system. Historically, Triad avoidance provided most of the commercial incentive for DSR and behind meter storage or generation. From April 2022, peak demand avoidance actions no longer reduce

[40] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/targeted-charging-review-significant-code-review

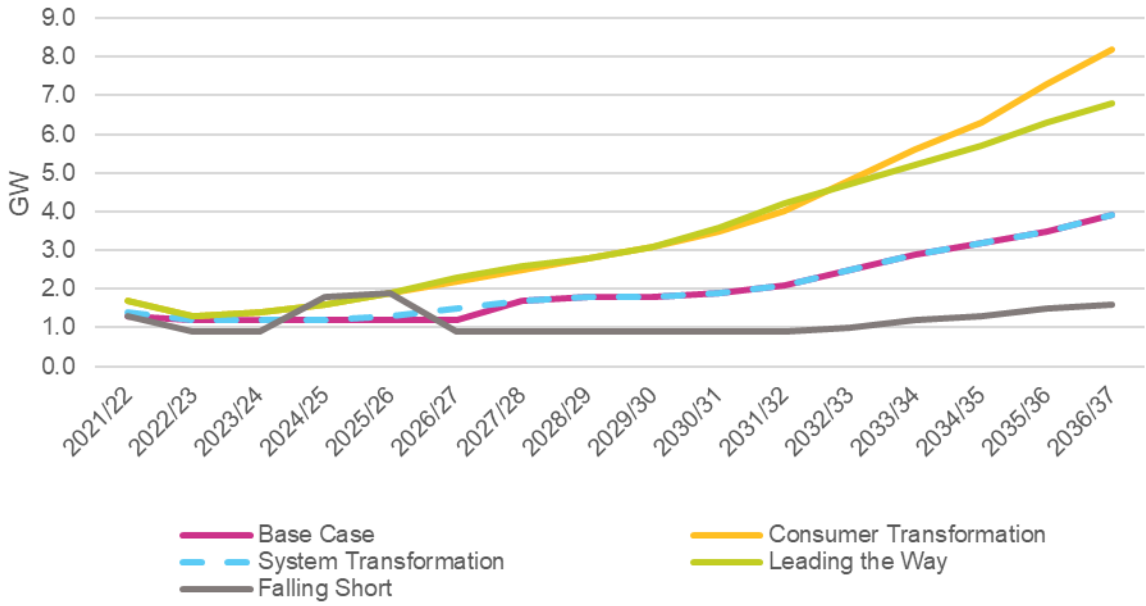
system charges to the extent they did previously. The commercial driver for DSR has pivoted away from system charges and moved mostly onto wholesale market price exposure. Changes to market behaviour and DSR are therefore difficult to anticipate as the duration of wholesale market prices may or may not be sufficient to justify DSR actions or investment in DSR enabling technologies (such as storage / generation or control systems).

Moving forward over the next ten to fifteen years, whilst there is growth in DSR across all scenarios, this has been reduced compared to last year's results where relatively high proportions of industrial peak demand were being shifted using DSR. In Falling Short, the DSR market develops slowly over time. In System Transformation, a significant proportion of industrial and commercial demand moves away from electricity and onto hydrogen. This results in low demand relative to the other net zero scenarios. As demands are lower when comparing with other scenarios, there is less industrial and commercial demand, and less DSR potential. Therefore, of the net zero scenarios, System Transformation has the lowest DSR levels. In Consumer Transformation, as hydrogen is a premium fuel, industrial and commercial demand electrifies as much as possible, particularly in the areas of space heat, commercial heat pumps and other secondary systems which are potentially available for DSR. Consumer Transformation has the highest customer electricity demand of the FES 2022 scenarios and therefore the highest levels of DSR to 2036/37. Although lower than Consumer Transformation, Leading the Way also has relatively high levels of DSR as this scenario reflects a rapid drive to as efficient and smart system as possible.

The range of DSR by 2036/37 is 1.4GW – 6.1 GW, which is less, although overlaps the FES 2021 range of 2.1 GW – 7.5 GW by 2035/36 modelled in FES 2021. This reflects the ongoing uncertainty due to the targeted charging review and the reduction in proportion of industrial peak demand which can be shifted compared to FES 2021.

We acknowledge that in the CM auctions, successful unproven DSR aggregators may contract with behind the meter generation as well as demand side response providers to fulfil their CM obligations.

Figure 16: Industrial and Commercial DSR to 2036/37



Power Responsive

Power Responsive[41] is a stakeholder-led programme, facilitated by National Grid ESO, to increase participation in flexible technology such as DSR, small scale generation and energy storage. Power Responsive class these technologies as demand side flexibility (DSF).

The programme brings the DSF industry and energy users together to work in a co-ordinated way. A key priority is to increase participation in DSF, by making it easier for industrial and commercial businesses to get involved and realise the financial and carbon-cutting benefits of participating in the energy flexibility industry.

The role of Power Responsive is to:

- Raise awareness of DSR and engage effectively with businesses;
- Shape the growth of the market in a joined-up way and ensure demand has equal opportunity with the supply side in balancing the system; and
- Power Responsive is overseen by a high-level steering group, composed of representatives from government, the regulator, system operators, and industry players.

4.7 Interconnector Capacity Assumptions

We derived our interconnector capacity assumptions from an analysis of individual projects that we aggregate to produce a total capacity of interconnection for each year. We assume that the total GB carbon price continues on a similar trajectory to the EU Emissions Trading Scheme. The GB Carbon Price Support is also assumed to continue in the near future. However, we have assumed that the current political uncertainty means that there are no new interconnectors in our Base Case by 2025/26 apart from those that have either already started construction or taken a final investment decision.

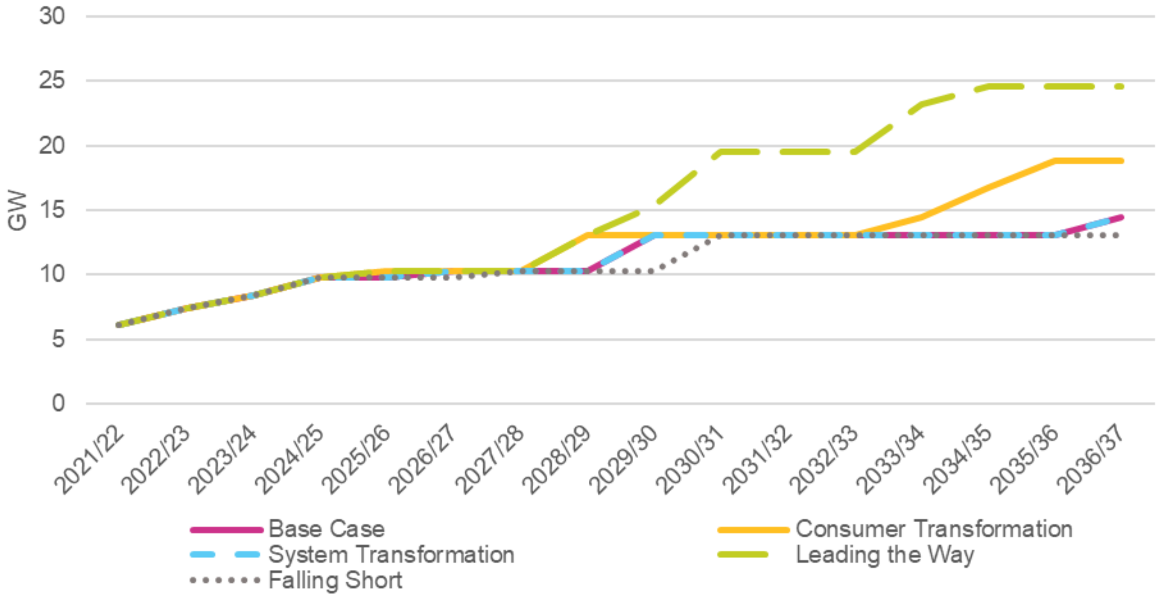
We identified potential projects and their expected commissioning dates to connect to GB. This information was derived from a range of sources including National Grid ESO's interconnector register, the electricity European Network of Transmission System Operators (ENTSO-E) Ten-Year Network Development Plan, the European Commission and the project developers themselves. We assessed each project individually against political, economic, social and technological factors to determine which interconnector projects would be built under each scenario. If it did not meet the minimum criteria, we assumed it will not be delivered in the given scenario, or that it will be subject to a commissioning delay. All projects which have reached final investment decisions are delivered, though they may be subject to delays in some scenarios. In all scenarios, we assumed that the supply chain has enough capacity to deliver all interconnector projects.

Figure 17 depicts the import capacity levels of interconnection for each scenario. Interconnector capacity is assumed to be higher in scenarios that meet decarbonisation targets. Furthermore, interconnector capacity is generally also higher in scenarios with higher levels of societal change. As such, the highest electricity interconnector capacity is in Leading the Way. Moving beyond 2030 towards 2050, Leading the Way has the highest electricity interconnector capacity followed by Consumer Transformation, System

[41] https://www.nationalgrideso.com/industry-information/balancing-services/power-responsive

Transformation and lastly Falling Short. The Base case has been aligned to System Transformation.

Figure 17: Import Capacity Levels for Interconnection (GW)



4.8 Sensitivities

Our modelling reflects uncertainty in future electricity supply and demand through the assumptions in the FES and Base Case. This includes uncertainty in generation, storage, and interconnector capacity, as well as peak demand and DSR. In addition, the LOLE calculation for each of the scenarios and the Base Case also reflects the natural variability of demand that may occur throughout the winter, wind output, availability of generation capacity and interconnector flows.

We also model sensitivities to assess uncertainties not fully reflected in the underlying scenario / Base Case assumptions or their associated LOLE calculations. Sensitivities are only applied to the Base Case such that only one variable is changed at a time. Further details on the sensitivities, including ones that were considered but not modelled, can be found in Annex A.6.

4.8.1 Weather

This sensitivity covers the potential uncertainty due to weather that may occur in a particular winter. The LOLE calculation in our modelling uses a relatively short weather history of 16 years. This means that we cannot be confident that this set will be statistically representative of future years. This sensitivity is therefore justified as the statistical uncertainty associated with colder and / or warmer winters may not be fully reflected.

The cold winter sensitivity is based on assessing the impact if the weather we experienced in winter 2010/11 were to happen again. Specifically, we use the demand and wind from winter 2010/11 only in the LOLE calculation instead of the full 16-year history that we use in the Base Case. The warm winter sensitivity is based on assessing the impact if the weather we experienced in winter 2006/07 were to happen again. Specifically, we use the demand and wind from winter 2006/07 only in the LOLE calculation instead of the full 16-year history that we use in the Base Case. These years are chosen because they represent the years that will have the highest and lowest requirements to meet 3 hours LOLE, respectively within our 16-year history. These winters do not represent best or worst-case scenarios as our relatively short history will not cover all potential weather scenarios.

4.8.2 High / Low Plant Availabilities

This sensitivity covers the potential uncertainty in the availability of conventional generation capacity. Conventional plant availabilities are based on the mean availability of the fleet during the winter peak period over the last seven years. As an average over a relatively small sample of seven data points, there is a statistical uncertainty in the mean value. This also means that there is a statistical uncertainty in the distribution of conventional generation used in the LOLE calculation. This sensitivity is therefore justified as the mean values may not fully reflect the statistical uncertainty of what may occur in future years.

This sensitivity only has an impact on capacity that has already been secured for future delivery years. Therefore, it is only included in our modelling for the 2023/24 T-1 auction. There is no material impact on the analysis for the 2026/27 T-4 auctions as the majority of capacity for that delivery year has yet to be secured.

Table 3 shows the availability assumptions used in this sensitivity. The low availability sensitivity assumes the availability of CCGT / CHPs and nuclear are one standard deviation below their mean values. It also assumes that coal is available with an availability of 50%, on the basis that we may only have one operational coal station in 2023/24. The high availability sensitivity assumes the availability of CCGT / CHPs is one standard deviation above its mean value. We no longer apply the high availability sensitivity to nuclear as the availability of the fleet has not reached such levels in the last five winters. As this sensitivity addresses uncertainty in the distribution of conventional generation used in the LOLE calculation, we do not include interconnectors. In the DDM, we model interconnectors using a separate distribution. We believe it is more appropriate to consider the uncertainty around interconnectors in the over- and non-delivery sensitivities.

Table 3: Assumptions for the low and high availability sensitivities

Technology	Low availability	High availability
CCGT / CHP & autogen	89%	93%
Nuclear	73%	N/A
Coal	50%	N/A

4.8.3 Low / High Demand

This sensitivity covers the potential uncertainty in forecasting the Base Case peak demand. The LOLE calculation reflects the natural variability of demand through a distribution. This distribution is based on historical half-hourly demand values from our 16-year history, which is scaled by the ratio of future peak demand to historical peak demand. The uncertainty in the future peak demand forecast leads to a statistical uncertainty in the demand distribution used in the LOLE calculation.

We have undertaken new modelling this year to better quantify the uncertainty in the Base Case peak demand forecast. This was the subject of a development project reported in Section 3.4. We have used the 10% and 90% percentile values from this modelling to inform the assumptions for the low and high demand sensitivities, which are set out in Table 4. Note that these sensitivities only apply in the years up to and including 2026/27.

Table 4: Peak demand assumptions for low and high demand sensitivities

Delivery year	Sensitivity	
	Low demand (GW)	High demand (GW)
2023/24	57.9	60.7
2026/27	59.5	62.1

4.8.4 Non-delivery

This sensitivity covers the future risk of non-delivery from capacity providers that we don't yet know about, in that they are unable to deliver in line with their Capacity Market agreements for the entire winter peak period – their de-rating factor is effectively zero. This uncertainty is not reflected in our Base Case assumptions, which only reflect non-delivery from capacity providers that is already known to us (e.g. terminations, market intelligence). This uncertainty is also not reflected in the calculation of station availabilities used to set technology de-rating factors. Further justification for this sensitivity comes from our analysis of past non-delivery (see Section 3.4) showed that we can be almost certain that some additional non-delivery will only become apparent after our recommendations – the uncertainty is in how much.

We have modelled the future risk in steps of 0.4 GW up to 6 GW non-delivery for the T-1 auction and up to 6.8 GW for the T-4 auction. The maximum level was informed by considering different types of non-delivery, summing them, and allowing for potential market response. This approach is consistent with that used in the 2021 ECR. We consider the maximum levels to be appropriate based on our analysis of past non-delivery presented in

Table 26 in the Annex. Table 5 shows our assumptions that have informed the maximum non-delivery. Further detail on these assumptions is provided in Annex A.6.1.

Table 5: Maximum non-delivery assumptions

Category	T-1 (GW)	T-4 (GW)
Large thermal	3.0	3.8
Nuclear	1.8	0.9
Distributed generation	0.7	0.7
Unproven DSR	0.4	0.3
Interconnectors	1.5	2.7
Sum of non-delivery[42]	**7.4**	**8.5**
Potential market response	-1.2	-1.7
Total	**6.0** (rounded to nearest 0.4)	**6.8** (rounded to nearest 0.4)

4.8.5 Over-delivery

This sensitivity covers the risk that market participants delivery more than what has been contracted through the Capacity Market (e.g. stations remaining open without an agreement). This sensitivity reflects over-delivery above what we have already assumed in the Base Case.

[42] Note that due to rounding totals may not equal sum of individual categories.

While we currently model non-delivery and over-delivery sensitivities separately, they can in essence, be considered as a continuum of net delivery. On this basis, we think it is appropriate to model them consistently with different types of over / non-delivery and associated market response. We have modelled up to 2.8 GW over-delivery in steps of 0.4 GW for the T-1 auction and up to 3.6 GW over-delivery in steps of 0.4 GW for the T-4 auction. Table 6 shows our assumptions that have informed the maximum over-delivery. Further details on these assumptions are provided in Annex A.6.1.

Table 6: Maximum over-delivery assumptions

Category	T-1 (GW)	T-4 (GW)
Large thermal	1.0	1.0
Nuclear	0.0	0.0
Distributed generation	1.5	1.5
Unproven DSR	0.3	0.3
Interconnectors	0.6	2.0
Sum of non-delivery	**3.4**	**4.8**
Potential market response	-0.7	-1.2
Total	**2.8** (rounded to nearest 0.4)	**3.6** (rounded to nearest 0.4)

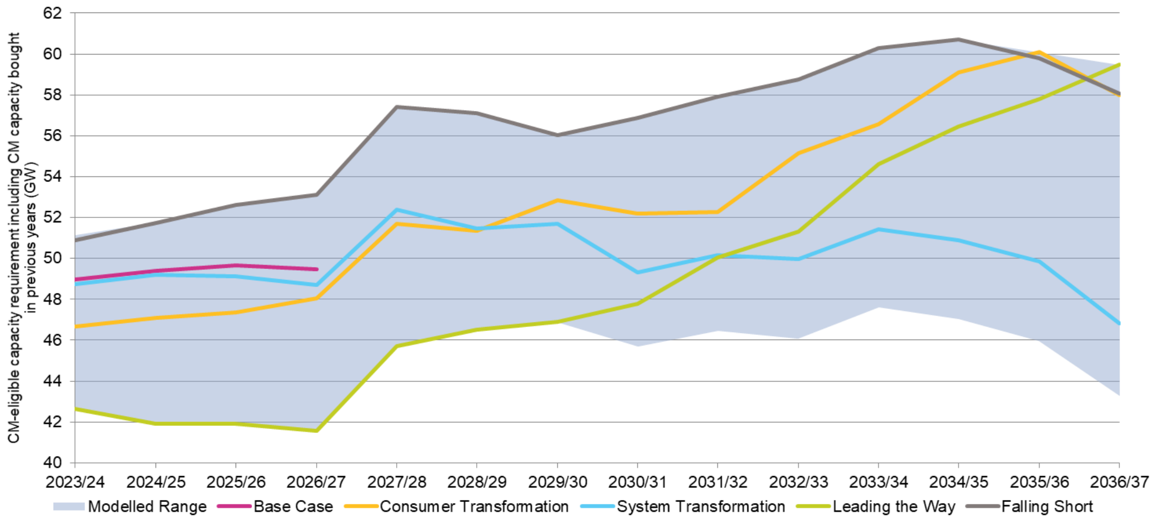
4.9 15-Year Horizon

This section considers the overall level of de-rated capacity requirement in future years, not just the years of interest for this report (2023/24 and 2026/27). It focuses on the total requirement for CM-eligible capacity and does not split each year's requirement into capacity secured in earlier years through T-1 and T-4 auctions. The requirement in 2023/24, 2024/25 and 2025/26 was derived from the 2023/24 model runs (see Chapter 6) and the capacity requirement from 2026/27 to 2036/37[43] from the model runs for 2026/27 (see Chapter 7). This section is included before the main results chapters to illustrate the ongoing requirement for CM-eligible capacity.

Figure 18 shows the range in modelled CM-eligible capacity requirement in future years including any new / refurbished capacity secured in previous years (note the shaded area corresponds to the modelled range including all scenarios and sensitivities). A table showing the data behind this chart can be found in the ECR Data Workbook.

[43] This chart was based on data taken from a near final version of the FES. Since then, the FES generation assumption from 2027/28 onwards have been revised slightly

Figure 18: Total CM-eligible Capacity required in Future Years



The total requirement for the non-delivery and over-delivery sensitivities is the same as the Base Case. For non-delivery cases, the increase in capacity required is offset by the reduction in contracted capacity closing before the target year. Similarly, for over-delivery cases, the decrease in capacity required is compensated for by CM-eligible plants providing additional capacity without a contract. The total requirements for sensitivities generally fall within the scenario range, particularly in the early years. However, in the later years, the warm winter sensitivity fall outside of the scenario range and the bottom of the range is set by the Base Case warm winter sensitivity in those years.

As can be seen in the chart above, the Consumer Transformation, Falling Short and Leading the Way scenarios show an increased requirement in general over most of the period, driven largely by an increase in peak demand. For the System Transformation scenario, the requirement remains relatively stable over most of the period, with increases in peak demand offset by increases in non-CM capacity. For System Transformation, there is a decline over the last few years resulting from an increase in low carbon capacity outside of the CM such as new nuclear. All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends. During the later years of the period, significant amounts of RO-supported wind farms will also come off support, further increasing the CM-eligible capacity requirement in most scenarios. In the final few years of the period, the requirement falls in some scenarios as more low carbon capacity becomes operational that is assumed to be outside of the CM.

There could be a potential risk of underutilised assets receiving support in future e.g. if new capacity is built for one year (when it is needed) that is not required in future years after that. However, in the case of coal power stations, the Government's policy is to close all unabated units by October 2024. The current nuclear fleet will also see a number of closures over this period, due to units reaching the end of their safe operational life. In addition, the Government has committed to end all unabated fossil fuel generation by 2035. These closures of existing capacity will ensure that any new capacity built in the early years of the Capacity Market will still be required in later years.

The capacity already secured for each year over the 15-year period can be obtained by looking in the CM registers and is summarised in the table and chart on page 5 of the final results report for the 2025/26 T-4 auction[44]. Note that the values in the 2025/26 T-4 auction results report may not include recent terminations and may differ from the values calculated by the DDM. Reasons for this include the awarded conventional capacity from previous T-4 auctions being greater than the de-rated TEC and revisions to duration-limited storage de-rating factors from the 2020/21 T-4 auction onwards. The ECR Data Workbook (DW.1 worksheet) contains a summary of total capacity secured in each auction to-date.

The above chart shows the level of CM capacity required to meet the Reliability Standard in all years from 2023/24. For 2022/23, we did not model the capacity requirement in each scenario / sensitivity as the T-1 capacity auction for that year has already happened. The forthcoming 2022/23 Winter Outlook Report[45] will include a view of electricity security of supply for the coming winter.

[44] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20DY%2025-26%20Final%20Auction%20Results%20Report%20V1.0.pdf
[45] https://www.nationalgrideso.com/research-publications/winter-outlook

5. De-rating Factors for CM Auctions

5.1 De-rating Factors for Conventional Plants, Storage and Renewables

The following Figures show the de-rating factors for conventional plants (Figure 19), storage (Figure 20 and Figure 21) and renewables (Figure 22 and Figure 23), respectively. The de-rating factors cover both 2023/24 T-1 and 2026/27 T-4 auctions. De-rating factors from the previous year's ECR are also shown in the Figures for comparison. No changes have been made to the methodology used to determine these de-rating factors since last year.

Conventional plant de-rating factors are calculated annually using the availability of transmission-connected generation during the winter peak period over the last seven years. Further detail behind these assumptions is provided in Annex A.5.4.

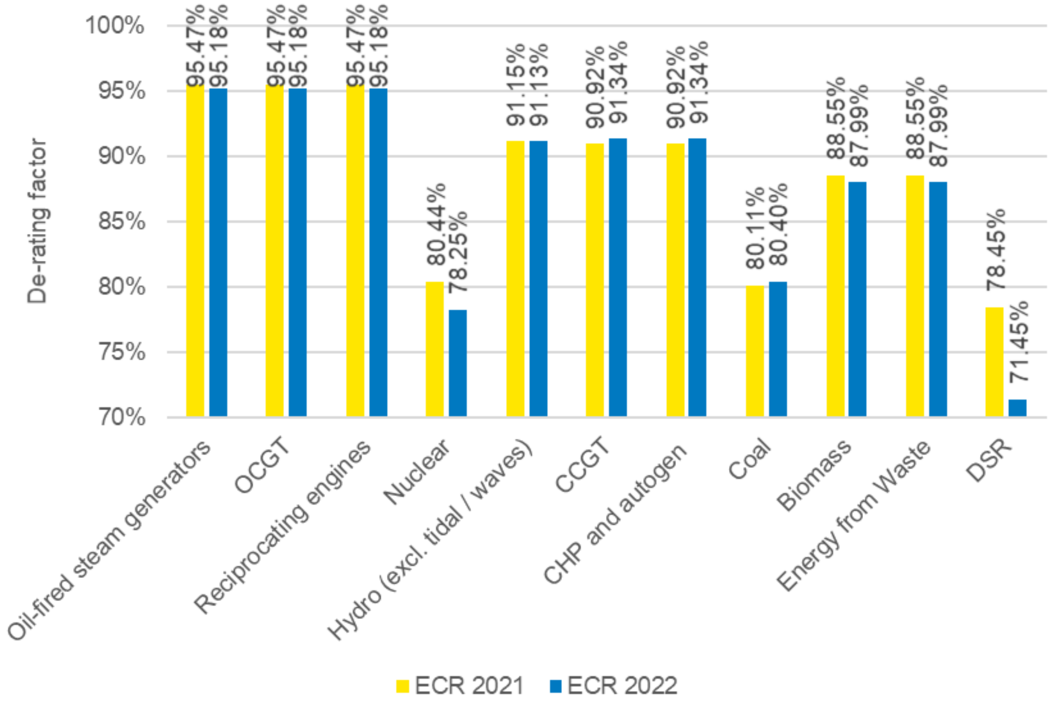
Storage de-rating factors apply to plant types that include: 'conversion of imported electricity into a form of energy that can be stored and the re-conversion of the stored energy into electrical energy'. This includes hydro generating units which form part of a Storage Facility (pumped storage), compressed air and battery storage technologies. Further details on our storage de-rating factor methodology can be found in our 2017 industry consultation[46]. Annex A.7 contains further details on the Base Case storage capacity assumptions and histograms illustrating the distribution of stress event durations for a system at 3 hours LOLE. This year, there is a much higher level of duration-limited storage capacity in the 2022 ECR Base Case than in the 2021 ECR Base Case particularly for the T-4 year (see Annex A.7 for more details). As a result of this increased capacity, the duration threshold corresponding to 95% of stress events has increased from 4.5 hours to 6 hours in the T-1 year and increased from 5.5 hours to 9.5 hours in the T-4 year, which combined with lower incremental Equivalent Firm Capacity (EFCs) also due to the increased duration-limited capacity, has resulted in significant reductions in the de-rating factors below the thresholds for those years.

Renewable de-rating factors are based on the methodology[47] that was consulted with the industry in February 2019. The values for wind in the 2022 ECR are similar to those in the 2021 ECR while those for solar are slightly higher.

[46] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

[47] https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20response%20-%20De-rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf

Figure 19: De-rating factors for conventional plants - detailed



* De-rating factors apply to both the 2023/24 T-1 and 2026/27 T-4 auctions.

Figure 20: De-rating factors for duration limited storage T-1 comparison

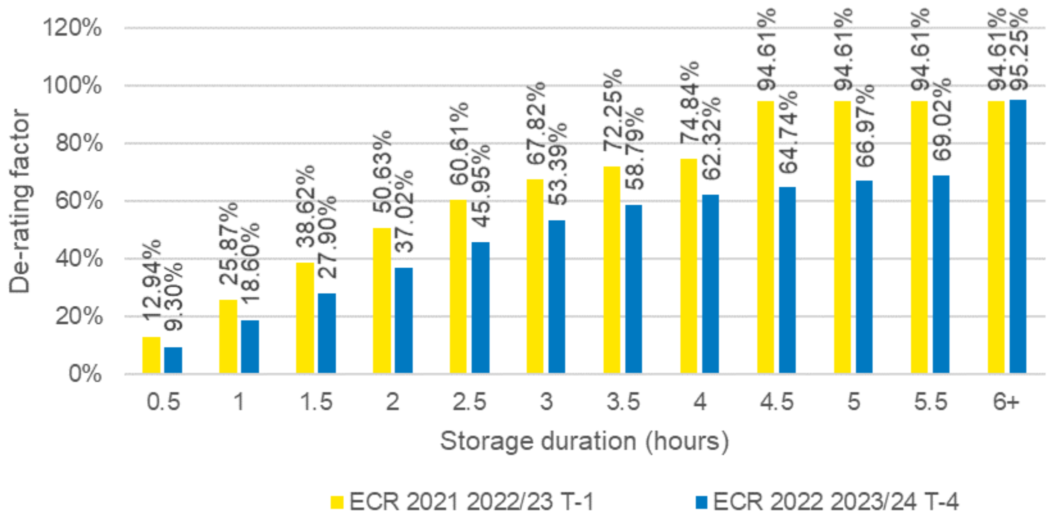


Figure 21: De-rating factors for duration limited storage T-4 comparison

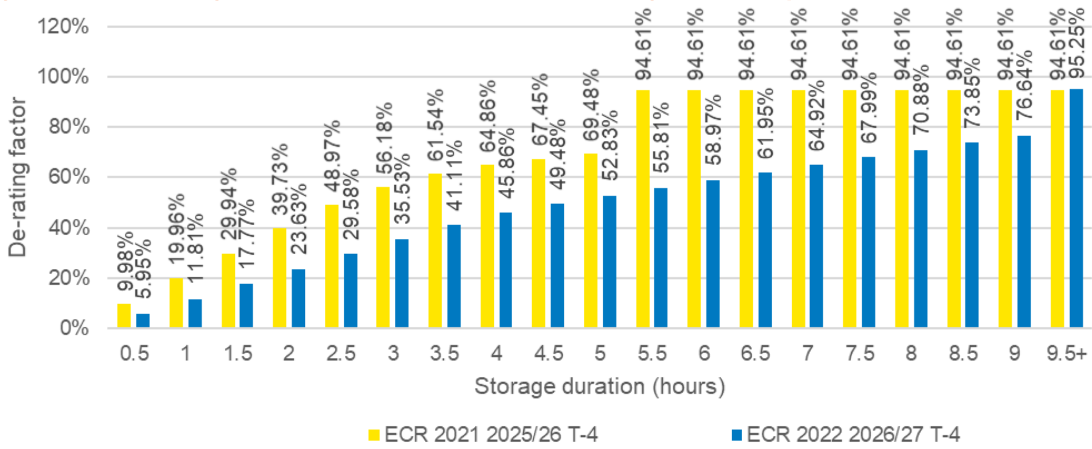


Figure 22: De-rating factors for renewables T-1 comparison

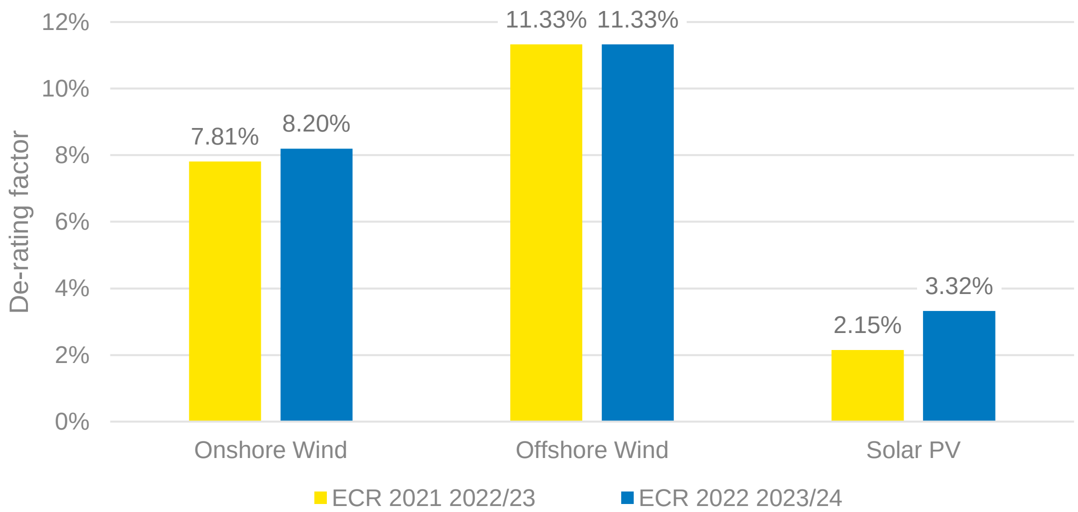
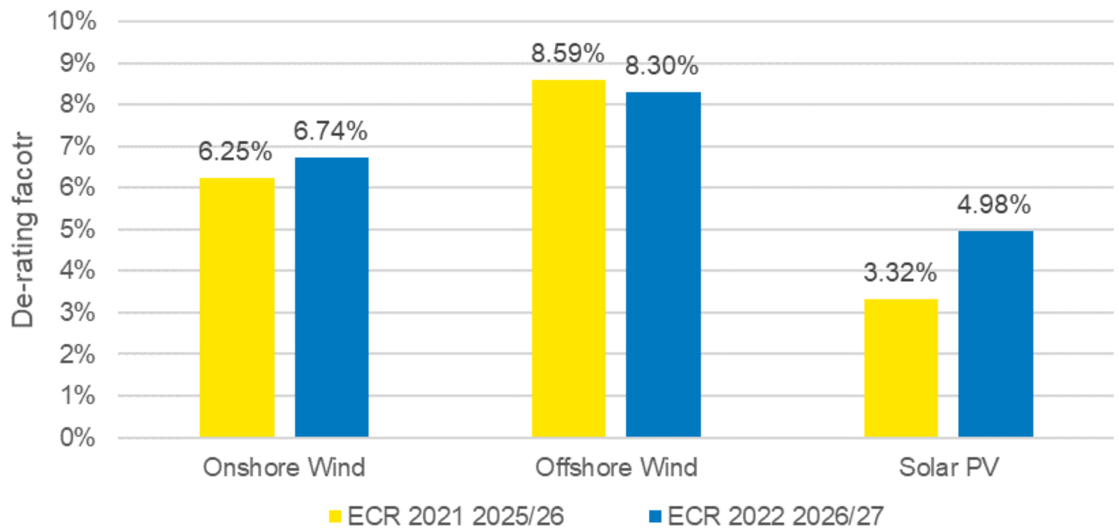


Figure 23: De-rating factors for renewables T-4 comparison



5.2 Interconnectors

Interconnectors are eligible to participate in both the 2023/24 T-1 and 2026/27 T-4 auctions except where they already have been awarded a Capacity Market agreement. All interconnectors that are expected to be operational for the start of the 2023/24 delivery year were already awarded contracts in the T-4 auction for 2023/24. Therefore, we have not provided modelling results for the 2023/24 T-1 interconnector de-rating factor ranges in this report.

The future of potential flows through interconnectors is very complex and, consequently, there is no single answer to the question of what can be assumed to flow through the interconnectors at times of system stress. This section outlines the various approaches National Grid ESO, in agreement with BEIS, Ofgem and the PTE, has considered in determining an appropriate de-rating factor range for each country so that the Secretary of State can then decide the de-rating factors to apply to individual interconnectors. The de-rating factor ranges in the ECR do not account for technical reliability, which is determined by BEIS.

Further details on our interconnector modelling assumptions are included in Annex A.11.

5.2.1 Methodology

The modelling methodology in this year's ECR is broadly similar to the approach we have taken over the last two years[48] and was set out in the briefing note published in May 2022[49]. This means that:

- We assume that interconnectors will be participating directly in the next round of CM auctions.
- We use our pan-European market model BID3 developed by Afry[50] and make use of the 'LOLE' module that we have used since 2020.
- The current modelling includes all remote markets that are forecast to be connected to GB and at least every market connected to the remote markets. A full list of modelled markets can be found in Annex A.11.2.
- We assess the potential contribution to security of supply from interconnectors during stress periods that strictly meet the condition where expected energy unserved is greater than zero[51] (i.e. we still have unserved energy after considering imports).
- GB demand is then scaled up significantly to ensure that there is load loss in all simulated time periods. The 105 time periods with the most load loss undergo detailed modelling in BID3. This is an average of 3 hours LOLE across 35 historic weather years.
- We use stochastic modelling of generator outages in Europe and sensitivity analysis to assess the potential impact of supply and demand uncertainty in Europe.
- The ECR only covers our modelling of future European electricity markets and doesn't include any information relating to the 'historical floor' that has not been included since the 2018 ECR.

[48] See Chapter 4.2 in https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202020.pdf
[49] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Modelling%20de-rating%20factors%20for%20interconnected%20countries%20in%20the%202022%20ECR.pdf
[50] https://afry.com/en/service/bid3-afrys-power-market-modelling-suite
[51] See
8.4.1 of the Capacity Market Rules: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/822019/Informal_Consolidation_of_Capacity_Market__Rules_July_2019.pdf

Since last year, we have worked with Afry to develop new model functionality in BID3 that provides greater insight on our interconnector modelling. For each scenario and sensitivity we model, we consider 1000 different outage patterns across 105 stress periods[52]. This reflects the stochastic nature of such outages and the related uncertainty in available generation in Europe. For each of these scenarios and sensitivities, we calculate a de-rating factor for each interconnected country, by taking the average of the interconnector imports. However, we recognise that taking a simple mean average, will not tell the whole story and may not reflect the underlying distribution.

In other words, we do not have the full picture relating to the potential risk on what interconnectors may flow during a stress event. For example, a de-rating factor of 50% for a particular scenario or sensitivity, may arise from interconnectors importing at maximum for half the periods and importing zero for the remaining half. While this gives an average de-rating factor of 50%, the risk profile for consumers would be different to a situation in which the interconnector flows during these periods were normally distributed around an average of 50%. Previously, we have not had the information available to consider this in our recommendations and subsequent decisions.

We have worked with Afry to develop enhanced model functionality in BID3 that will allow us to provide greater insight on the underlying data that informs the averages. In this ECR we will present average derating factors as usual, but we will supplement these with percentile plots of underlying hourly distributions of derating factors over all random cases. This provides greater insight on the risk around the mean averages. Percentile plots along with relevant insight are presented in Annex A.12.

We note that the new methodology results in a significant overhead in simulation run time due to the additional data that needs to be generated. Therefore, there is a trade-off between providing additional insight and modelling the full breadth of sensitivities we have run in the past. We note, however, that while some sensitivities have been crucial in providing the plausible range of outcomes – the French nuclear sensitivity for example – others are effectively covered within these ranges and are run mainly for completeness. Therefore, this has given us the flexibility to reduce the number of sensitivities we model in order to provide richer insight on the ones that are more likely to inform the final outcome, without compromising the overall robustness.

Data sources

In the 2021 ECR, our assumptions for Europe were based on a data set that we procured from Afry. This meant that we represented Europe with a single scenario. Since last year, we have worked with Afry to develop two bespoke European scenarios as part of our Future Energy Scenarios (FES). We believe that this represents a significant step forward from last year because:

1. Our European scenarios are now consistent with the latest European policy on net zero.
2. They have been designed to align with the Consumer Transformation and System Transformation scenarios for Great Britain, which meet net zero in our FES.
3. It should allow us to share more details of the scenario assumptions to improve transparency with our stakeholders, which we were not able to do last year. Initially we intend to publish capacity by technology and demand for European countries. These will be published as part of the FES data workbook which will be hosted in the FES area of the ESO website in July 2022.[53]

The two new European scenarios are referred to as the EU Consumer Transformation (EU CT) and the EU System Transformation (EU ST) scenarios. EU CT is aligned with FES

[52] This is consistent with 35 years historical weather in our 2022 ECR modelling * 3 hours / year LOLE
[53] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Consumer Transformation and FES Leading the way. EU ST is aligned with FES System Transformation, Falling Short and the Base Case.

The European scenario assumptions also include an extra weather year, such that we now have a 35-year history covering 1985 – 2019, helping us capture even more variety in weather patterns across Europe and further improve the robustness of the modelling.

Our European scenarios were developed before the invasion of Ukraine by Russia. As such, they will not reflect the potential uncertainty on energy security and any subsequent changes in the market outlook. We have included some sensitivities that consider this potential uncertainty.

5.2.2 European Sensitivities

We use sensitivities to assess the potential uncertainty of supply and demand in Europe beyond the assumptions in the scenarios. Our modelling approach means that we have completed around 350,000 simulations[54] each covering 35 years' historical weather for the 2026/27 T-4 auction.

Table 7 shows the sensitivities modelled. Note that the sensitivities carried out cover a wide range, only one point in this range is selected for presentation in the results presented in this chapter.

Table 7: European Scenario Sensitivities

Sensitivity Name	Description	Justification
Ireland Thermal	Scaling thermal plant capacity in Ireland from 100% to 0% in 10% steps.	Ireland has low levels of interconnection, any change in thermal capacity will have a large effect on the de-rating factor.
European Demand	Scaling European demand from 100% to 90% in steps of 1%	Our scenarios are aligned to net zero targets, which mean that they assume demand increases as we electrify heat and transport. There is significant uncertainty on this growth and current high inflation, as well as ongoing risks relating to the Covid pandemic could put downward pressure on demand. In addition, the European Commission recently proposed reduction to energy consumption as a way to support decarbonisation[55].
France Nuclear	Reducing nuclear plant capacity in France from 0GW to -20GW in 2GW steps.	France relies heavily on nuclear power and has high electricity demand. Recent history has shown that type faults can remove a large amount of capacity for extended periods. In addition, French nuclear generation has followed a downward trend in recent years and is currently at a historic low.
European Gas	Scaling gas generating capacity (including OCGT, CCGT both conventional and CHP) from 100% to 75% in 2.5% steps.	This sensitivity considers the potential impact of lower gas supplies being available for gas-fired generation in Europe.
Belgian Nuclear	Scaling Belgian Nuclear linearly from projected 2026/27 levels to current levels.	Belgium has delayed the phase out of nuclear keeping two of seven reactors open

[54] We have 5 scenarios in FES (Base Case + 4 scenarios) each simulated with 70 sensitivities and 1000 outages cases, giving a total of 350,000. Prior to the 2019 ECR we used a full hourly dispatch in which we only modelled around 20 cases and discarded the vast majority of the data as it didn't correspond to a stress period.
[55] https://ec.europa.eu/commission/presscorner/detail/en/qanda_22_3132

Sensitivity Name	Description	Justification
	i.e. from 2.1GW to 4.9GW in steps of approximately 300MW.	to 2035. It's possible that closures of other stations may be delayed.
Germany Coal	Doubling coal (both hard and lignite) plant capacity (including CHP) in Germany from 23.9GW to 47.8GW in steps of approximately 2.4GW.	Germany may delay the phase out of coal to reduce reliance on gas-fired generation.
Norway Hydro	Scaling hydro plant capacity in Norway (simulating a lack of water rather than closure of the plant) from 100% to 0% in 10% steps.	Although the 35 weather years should cover a range of hydro inflow, it is possible that these years do not cover all possible inflow levels.

Our interconnector analysis requires us to provide a range for each interconnected country. In the 2021 ECR the upper end of the range was set by the supply and demand assumptions in the European scenarios. These assumptions showed that there was a surplus of capacity in Europe with many countries reporting LOLE values well below their Reliability Standards indicating limited potential for extra capacity being required. As such, we considered there was less scope for upside sensitivities in last year's report (essentially, they would have had little impact on our modelled ranges).

Our updated European scenarios show that margins are now expected to be a lot tighter in many of the major European markets with many markets reporting values close to or in excess of 3 hours LOLE. This is also consistent with the findings of ENTSO-E's 2021 European Resource Adequacy Assessment[56]. As such, we have also not modelled the European LOLE standard sensitivities included in previous ECRs. We consider there may be more potential for upside sensitivities and so we have chosen a number of upside sensitivities to set the upper ends of the derating factor ranges. Overall, we consider there to be less scope for upside sensitivities as compared to downside ones. This is because there is less opportunity available for any market to bring new plant online within the modelled timescales. We have considered the following sensitivities.

1. We explore the effect of increasing German coal capacity. This is in direct conflict with the German and European net zero agenda. However, in light of the expected tight margins in Germany and neighbouring markets as well increasing uncertainty around international gas supply, this would provide a reliable means for Germany to protect security of supply.
2. We also explore the effect of increasing Belgian nuclear capacity. Belgium has recently reviewed plans to phase out nuclear capacity by 2025 and will now extend the operation of two of seven reactors to 2035. Extending the operation of further reactors is a plausible reaction to supply uncertainty in the international market.
3. Our European scenarios are aligned to net zero targets. These scenarios assume demand increases as Europe decarbonises. There are potential economic risks that could put downward pressure on demand growth that could see demand out-turn lower than our assumptions. In addition, the European Commission recently proposed reduction to energy consumption as a way to support decarbonisation[57].

There is much greater scope in choosing the sensitivity that sets the lower end of the range. For this we have primarily considered the following sensitivities.

1. We have observed high levels of nuclear outages in France during winters 2016/17, 2017/18 and 2019/20, as well as the first half of winter 2021/22. We are also currently expecting low availability of the French nuclear fleet in the coming winters due to enhanced maintenance of the fleet. In addition, nuclear generation can be

[56] https://www.entsoe.eu/outlooks/eraa/2021
[57] https://ec.europa.eu/commission/presscorner/detail/en/qanda_22_3132

prone to type faults that can significantly reduce the amount of available capacity at short notice. Such events can also impact margins in other European countries.

2. Europe relies on Russia for a significant proportion of its gas supply. This sensitivity considers the potential impact of lower gas supplies being available for gas-fired power generation in Europe.
3. Ireland is not directly connected with mainland Europe and is to some extent insulated from European market shifts. We therefore need to consider the Irish market directly in our modelling to capture plausible uncertainty in interconnector flows.
4. Norway possesses a large natural hydro capacity and is to some extent insulated from European market shifts. Norway is also highly interconnected and is a net electricity exporter. Movement in Norwegian interconnector flows can have a significant impact throughout Europe.

Each sensitivity in Table 7 consists of a number of discrete points, all of which are simulated for each scenario and delivery year. Therefore, for each sensitivity a level must be chosen which is deemed to be credible.

German Coal Sensitivity

In our German coal sensitivity, we have scaled both hard coal and lignite plant capacity from 100% to 200% in 10% steps. This corresponds to a doubling of capacity from 23.9GW to 47.8GW in steps of approximately 2.4GW. We report interconnector derating factors where hard coal and lignite plant capacity has been scaled to 140% of projected 2026/27 levels. This is equivalent to an increase of approximately 9.5 GW compared to the assumptions in our European scenarios and represents no change in capacity from 2022/23 levels.

European Demand Sensitivity

In our European demand sensitivity, we reduce demand in Europe from 100% to 90% in steps of 1%. There is little precedent to place a specific value on the exact decrease in demand expected from an economic downturn in Europe. We note from FES 2022 historical demand that in the year following the financial crises of 2007 demand in Great Britain dropped by approximately 4%. Therefore, in our European demand scenario we report interconnector derating factors at 96% of projected 2026/27 demand. This is equivalent to an approximate 23 GW reduction in peak demand across Europe compared to the assumptions in our European scenarios.

Belgian Nuclear Sensitivity

In the Belgian nuclear sensitivity, we increase Belgian nuclear capacity linearly from 2.1GW to 4.9GW in steps of approximately 300MW. This is equivalent to increasing the 2026/27 capacity in our European scenarios to the current levels. We report interconnector derating factors at the top end of this range. We consider this to be plausible in light of ongoing uncertainty in international energy markets.

European Gas Sensitivity

In the European gas sensitivity, we reduce European gas generation capacity from 100% to 75% in steps of 2.5% due to potential lower gas supplies for gas-fired power generation in Europe. Clearly, there is significant uncertainty here. In our European gas sensitivity, we report interconnector derating factors where there is a 10% reduction of gas capacity compared to projected 2026/27 levels in our scenarios. This translates to an approximate 23 GW reduction in capacity from 2026/27 levels compared to our European scenarios.

France Nuclear Sensitivity

Recent history has shown that the large nuclear fleet in France is susceptible to type faults. There have been several instances where around 10 GW of nuclear plant has been on long term unplanned outage during the winter months (for example Dec 2016, Dec 2017, Dec 2019 and Jan 2020)[58]. In addition, while the new European Pressurised Reactor (EPR) unit at Flamanville is due to commission in time for the 2026/27 T-4 delivery period, this project has already been significantly delayed.

There has been a declining trend in French nuclear generation over the past several years. The impact of Covid-19 on maintenance schedules, the closure of Fessenheim and planned ten-year inspections have played a significant role. Unplanned outages including control and repair works on pipes affected by stress corrosion[59] have also had a major influence resulting in historically low French nuclear generation in the year to date.

We have scaled French nuclear capacity in 2026/27 to reflect an availability profile similar to that expected by EDF in 2023/24[60]. We have also included a reduction of 10 GW for unplanned outages and a further 2GW to reflect the risk associated with Flamanville. In total this corresponds to an approximate 20 GW reduction in capacity from our 2026/27 scenario levels.

Ireland Thermal and Norway Hydro Sensitivities

Irish and Norwegian derating factors are to some extent insulated from European market shifts. In Ireland, this is a result of there being no direct connection to the European mainland. In Norway this is a result of a surplus of natural hydro capacity. The Irish and Norwegian sensitivities seek to model interconnector derating factors in these markets in the wake of plausible downturns in thermal and hydro capacities respectively.

For the Ireland thermal sensitivity, we reduce thermal plant capacity from 100% to 0% in steps of 10%. We report interconnector derating factors at the scaling level that brings the market to 8 hours LOLE in line with the Irish security standard[61]. This corresponds to a 30% reduction in the FS scenario and a 40% reduction in all other scenarios.

For the Norway Hydro capacity sensitivity we reduce hydro plant capacity from 100% to 0% in steps of 10%. We report interconnector derating factors at the scaling level that brings the market to 3 hours LOLE. This corresponds to a 20% reduction in all scenarios.

Like previous years, strategic reserves held outside the market in neighbouring countries have also not been included in our modelling. This is because we do not believe they could be deployed to support adequacy in Great Britain due to conditions of State Aid approval.

[58] French nuclear capacity is 63 GW. Extended French nuclear outages meant availability in winter 2016/17 was low. Available nuclear capacity was around 50 GW or lower in December 2016, slowly rising to around 55 GW by late January 2017. In addition, nuclear output was also low in December 2017 (around 50 GW), winter 2019/20 (typically below 50 GW) and winter 2020/21 (around 50 GW). Based on nuclear generation output data available on RTE's website: https://www.rte-france.com/en/eco2mix/eco2mix-mix-energetique-en.
[59] https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/update-nuclear-on-may-18th-2022
[60] https://www.edf.fr/en/the-edf-group/dedicated-sections/journalists/all-press-releases/edf-updates-its-2023-french-nuclear-output-estimate
[61] Northern Ireland has a Reliability Standard of 4.9 hours

Table 8: Pan-European modelling runs

Scenarios	Graph name	Description	EU Scenario alignment
Average of FES scenarios	Average	Average of de-rating factors for BC, CT, ST, LW & SP	N/A
Base Case	BC	2022 Future Energy Scenarios – Base Case	EU ST
Consumer Transformation	CT	2022 Future Energy Scenarios – Consumer Transformation	EU CT
System Transformation	ST	2022 Future Energy Scenarios – System Transformation	EU ST
Leading the Way	LW	2022 Future Energy Scenarios – Leading the Way	EU CT
Falling Short	FS	2022 Future Energy Scenarios – Falling Short	EU ST

5.2.3 BID3 Pan-European Model Results

The imports as a percentage of interconnector capacity, from all the pan-European simulations, are shown in Table 9 for 2026/27.

Each of the results tables contains results for the 5 scenarios and the minimum and maximum sensitivities (i.e., the sensitivities that result in the lowest and highest de-rating factors) from all of the sensitivities for each of the scenarios. Note that the minimum and maximum sensitivities may vary for each scenario. The values that set range for each market are typeset in bold and underlined.

Table 9: Simulation results: 2026/27 imports as percentage of interconnector capacity

	ECR 2021 2025/26 T-4		Scenarios					Minimum Sensitivity					Maximum Sensitivity				
Country	Min.	Max.	BC	CT	ST	LW	FS	BC	CT	ST	LW	FS	BC	CT	ST	LW	FS
Ireland	10	97	85	76	84	74	90	23	18	22	**14**	45	90	84	89	83	**94**
France	59	97	88	83	88	83	88	30	32	**30**	36	33	**97**	94	97	94	97
Belgium	22	82	80	76	81	76	80	31	33	**31**	37	34	95	92	**95**	92	94
Netherlands	49	88	75	72	76	72	75	**51**	52	51	54	54	92	89	**92**	89	91
Denmark	47	87	70	69	71	69	71	48	48	**48**	50	51	90	87	**91**	87	89
Norway	78	96	100	100	100	100	99	86	92	87	93	**84**	**100**	100	100	100	100

5.2.4 Country de-ratings

The results for each of the scenario averages are shown in Figure 24 to Figure 29 and Table 10 to Table 15.

As this methodology is based around the modelling of European markets, step changes in results could potentially occur between years due to changes in demand, generation mix and the resulting capacity margin. A shift in one country can impact flows from surrounding countries, as can be seen by the impact of Norwegian hydro capacity reductions on Belgium, Netherlands and Denmark interconnector flows. Modelling flows across Europe for the auction year gives confidence that these interactions have been reflected in the modelled range of de-rating factors.

European margins are falling over the next few years. This along with increased interconnector capacity has a downward pressure on interconnector de-rating factors in 2026/27.

Ireland:

The modelled ranges for Ireland are 14% to 94% for 2026/27.

Ireland is a single energy market economically but currently there are limited physical links between the north and south. This is expected to be rectified with an additional North/South link, planned to be commissioned in 2025[62]. Ireland was modelled as a single price area assuming no restrictions on flows within the all-island system.

Eirgrid is forecasting there will be downward pressure on generation in its 2021 All-Island Generation Capacity Statement[63]. This is partly due to the Irish Capacity Market which currently targets 8 hours LOLE through Capacity Market auctions (The standard in Northern Ireland is 4.9 hours LOLE and assumes a 200 MW capacity reliance on Ireland). However, the auction for the period 01 October 2024 to 30 September 2025 failed to clear sufficient capacity for the Republic of Ireland and there have been withdrawals of previously secured capacity since. For the all-island system, Eirgrid predicts a capacity surplus in 2026.

The results for Ireland show a very wide range. The Ireland thermal sensitivity demonstrates the reduction in interconnector de-rating factor if Ireland were to close enough thermal plant to meet their security of supply standard. Unlike all the other markets shown in this section Ireland has no interconnection to other markets (ignoring GB) and therefore cannot act as an intermediary for excess capacity from other markets.

No results are shown for the German coal, Belgian nuclear, France nuclear or Norway hydro sensitivities because Ireland does not have any interconnection to these markets except via Great Britain (the modelling assumes that Great Britain will not export during stress events).

[62] https://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf

[63] https://www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf

Figure 24: Irish interconnector de-rating factors 2026/27

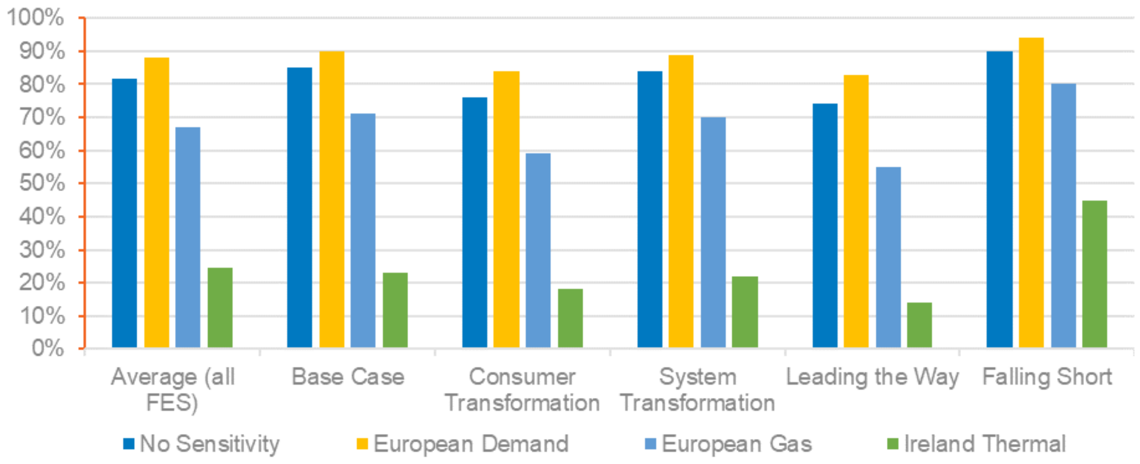


Table 10: Irish interconnector de-rating factors 2026/27

Calculation	Average	BC	CT	ST	LW	FS
Scenario	82	85	76	84	74	90
Minimum Sensitivity	24	23	18	22	14	45
	N/A	Irish Thermal	Irish Thermal	Irish Thermal	Irish Thermal	Irish Thermal
Maximum Sensitivity	88	90	84	89	83	94
	N/A	European Demand	European Demand	European Demand	European Demand	European Demand
European Gas	67	71	59	70	55	80

France:

The modelled ranges for France are 30% to 97% for 2026/27.

The French generation margin is generally positive, although French demand is very weather sensitive, so very cold weather results in demand exceeding domestic generation. As the interconnector capacity with France grows, we may see de-rating factors falling further in the future particularly if nuclear availability is low. France is well interconnected to other markets in Europe which gives access to excess capacity in these markets. The French de-rating factor is particularly affected by the French nuclear sensitivity.

Figure 25: French interconnector de-rating factors 2026/27

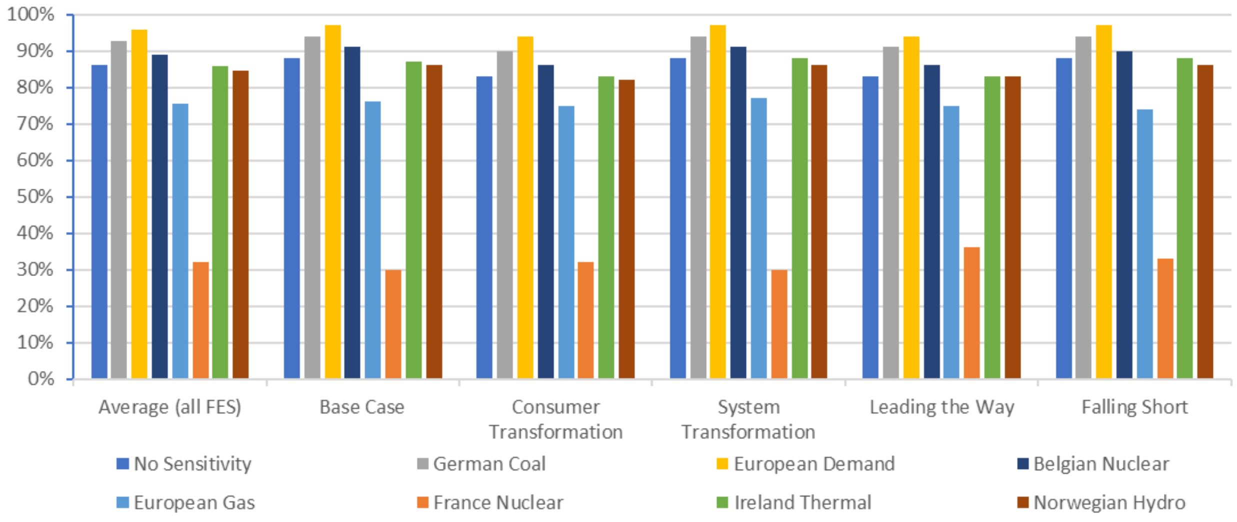


Table 11: French interconnector de-rating factors 2026/27

Calculation	Avg.	BC	CT	ST	LW	FS
Scenario	86	88	83	88	83	88
Minimum Sensitivity	32	30	32	30	36	33
	N/A	French Nuclear	French Nuclear	French Nuclear	French Nuclear	French Nuclear
Maximum Sensitivity	96	97	94	97	94	97
	N/A	European Demand	European Demand	European Demand	European Demand	European Demand
German Coal	93	94	90	94	91	94
Belgian Nuclear	89	91	86	91	86	90
European Gas	75	76	75	77	75	74
Irish Thermal	86	87	83	88	83	88
Norwegian Hydro	85	86	82	86	83	86

Belgium:

The modelled ranges for Belgium are 31% to 95% for 2026/27.

Belgium had planned to phase out nuclear power by 2025 but has since delayed that decision for two of its seven reactors until 2035. There is a chance Belgium could make a similar decision on its remaining five reactors and this is the justification for carrying out this sensitivity. Both the European demand and the German coal sensitivities give higher derating factors than the Belgian nuclear sensitivity for Belgium. The French nuclear sensitivity sets the bottom of the range for Belgium. These results indicate a heavy reliance on neighbouring markets.

Figure 26: Belgium interconnector de-rating factors 2026/27

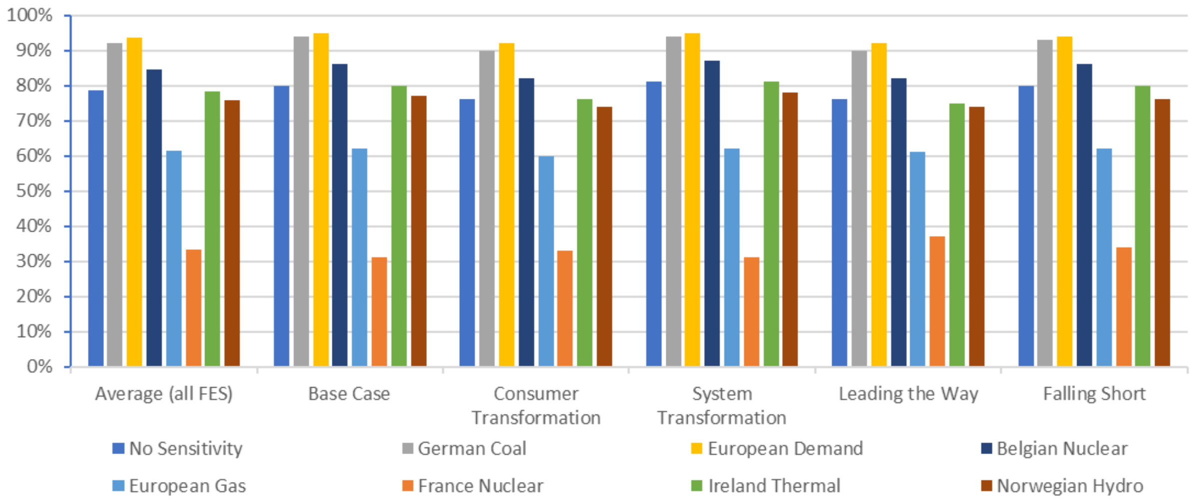


Table 12: Belgium interconnector de-rating factors 2026/27

Calculation	Avg.	BC	CT	ST	LW	FS
Scenario	79	80	76	81	76	80
Minimum Sensitivity	33	31	33	31	37	34
	N/A	French Nuclear	French Nuclear	French Nuclear	French Nuclear	French Nuclear
Maximum Sensitivity	94	95	92	95	92	94
	N/A	European Demand	European Demand	European Demand	European Demand	European Demand
German Coal	92	94	90	94	90	93
Belgian Nuclear	85	86	82	87	82	86
European Gas	61	62	60	62	61	62
Irish Thermal	78	80	76	81	75	80
Norwegian Hydro	76	77	74	78	74	76

Netherlands:

The modelled ranges for Netherlands are 51% to 92%.

The modelling assumed a firm import capacity of 1000 MW and the de-rating factor range is based on this capacity. The maximum historical imports have been 1200 MW although this can only be sustained for a very short time and so is not considered firm.

Figure 27: Netherlands interconnector de-rating factors 2026/27

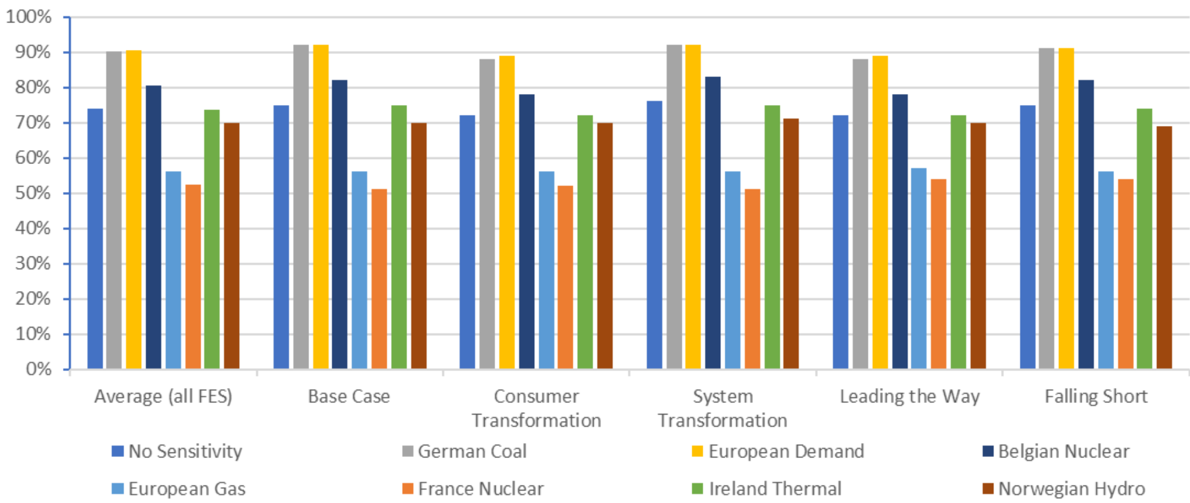


Table 13: Netherlands interconnector de-rating factors 2026/27

Calculation	Avg.	BC	CT	ST	LW	FS
Scenario	74	75	72	76	72	75
Minimum Sensitivity	52	51	52	51	54	54
	N/A	French Nuclear	French Nuclear	French Nuclear	French Nuclear	French Nuclear
Maximum Sensitivity	91	92	89	92	89	91
	N/A	European Demand	European Demand	European Demand	European Demand	European Demand
German Coal	90	92	88	92	88	91
Belgian Nuclear	81	82	78	83	78	82
European Gas	56	56	56	56	57	56
Irish Thermal	74	75	72	75	72	74
Norwegian Hydro	70	70	70	71	70	69

Denmark:

The modelled ranges for Denmark are 48% to 91%.

Figure 28: Denmark interconnector de-rating factors 2026/27

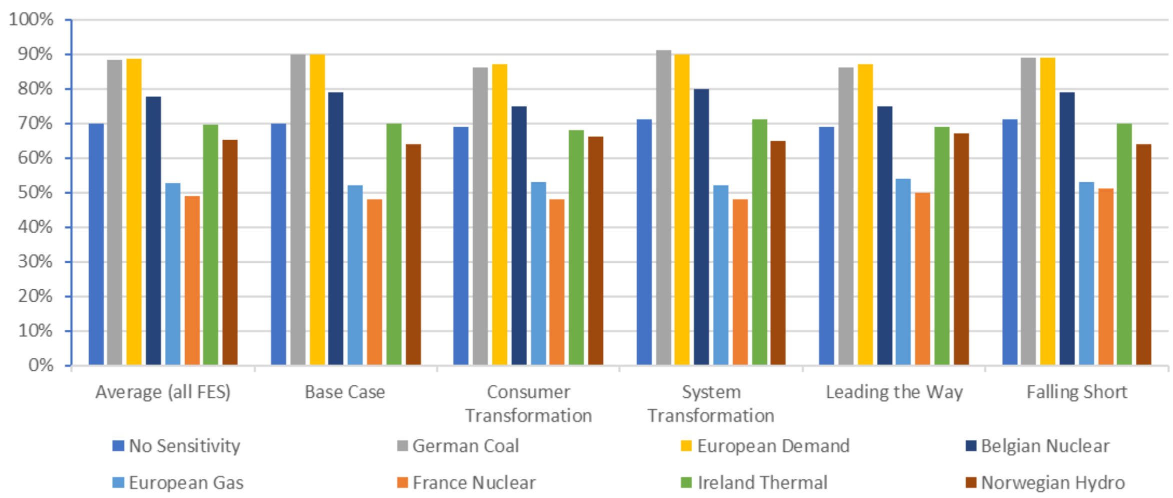


Table 14: Denmark interconnector de-rating factors 2026/27

Calculation	Avg.	BC	CT	ST	LW	FS
Scenario	70	70	69	71	69	71
Minimum Sensitivity	49	48	48	48	50	51
	N/A	French Nuclear	French Nuclear	French Nuclear	French Nuclear	French Nuclear
Maximum Sensitivity	89	90	87	91	87	89
	N/A	German Coal	European Demand	German Coal	European Demand	German Coal
European Demand	89	90	87	90	87	89
German Coal	88	90	86	91	86	89
Belgian Nuclear	78	79	75	80	75	79
European Gas	53	52	53	52	54	53
Irish Thermal	70	70	68	71	69	70
Norwegian Hydro	65	64	66	65	67	64

Norway:

The modelled ranges for Norway are high across all scenarios giving a range of 84% to 100% for 2026/27.

The high interconnector de-rating factors are due to the large volume of hydro capacity in Norway. The lower end of the range demonstrates the reduction in interconnector de-rating factor if Norway were to lose enough Hydro capacity to meet 3 hours LOLE.

Figure 29: Norway interconnector de-rating factors 2026/27

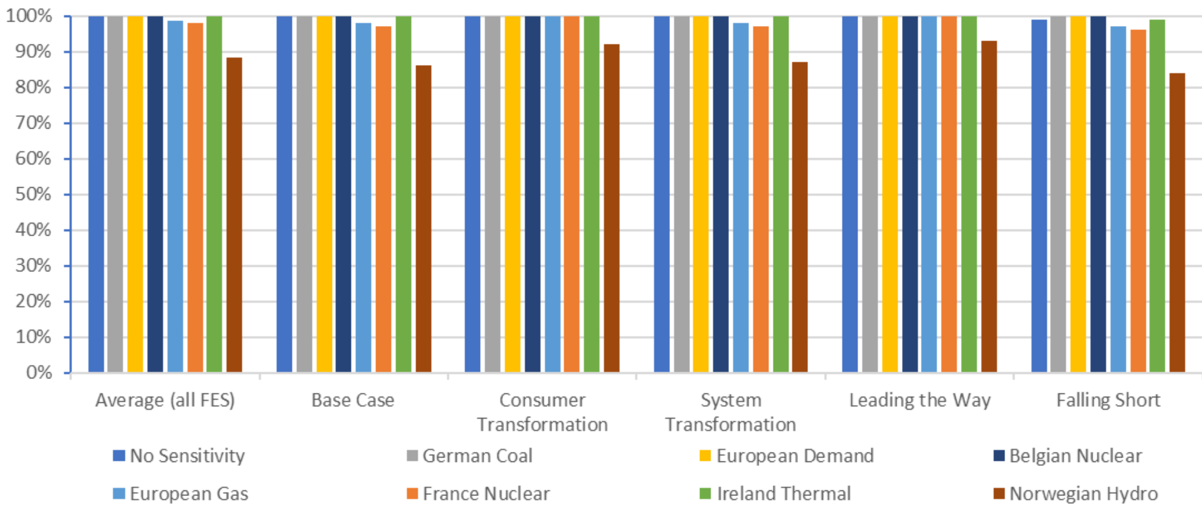


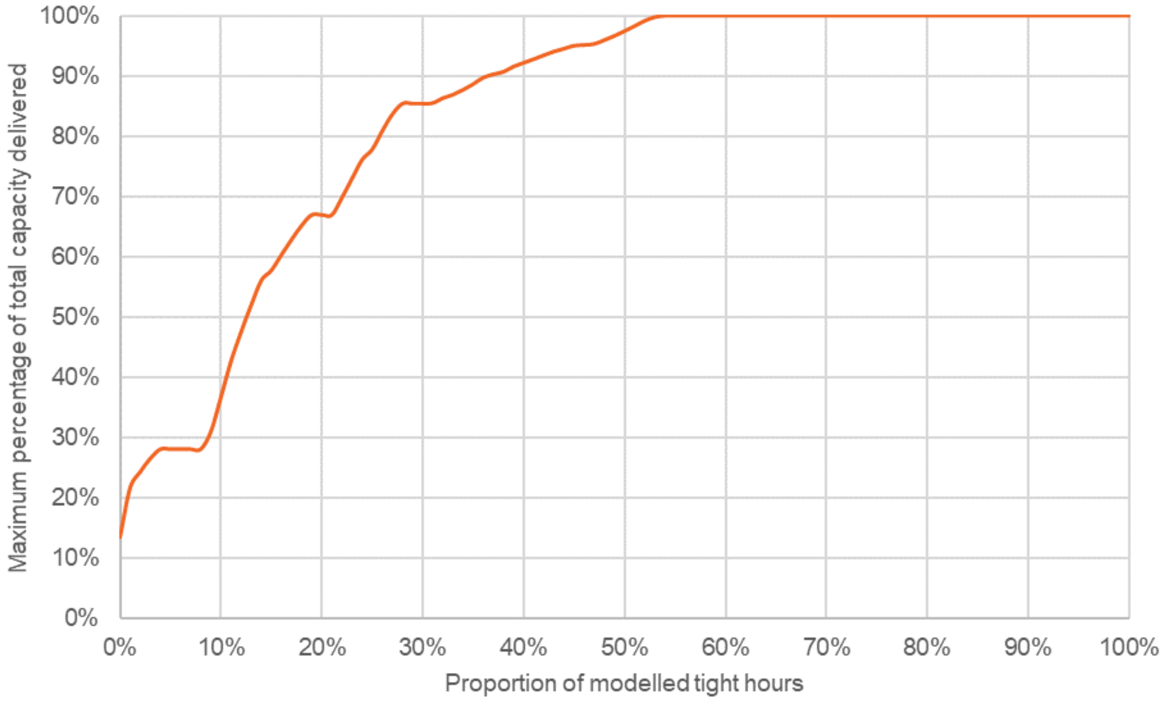
Table 15: Norway interconnector de-rating factors 2026/27

Calculation	Avg.	BC	CT	ST	LW	FS
Scenario	100	100	100	100	100	99
Minimum Sensitivity	88	86	92	87	93	84
	N/A	Norwegian Hydro	Norwegian Hydro	Norwegian Hydro	Norwegian Hydro	Norwegian Hydro
Maximum Sensitivity	100	100	100	100	100	100
	N/A	European Demand	European Demand	European Demand	European Demand	European Demand
German Coal	100	100	100	100	100	100
Belgian Nuclear	100	100	100	100	100	100
European Gas	99	98	100	98	100	97
French Nuclear	98	97	100	97	100	96
Irish Thermal	100	100	100	100	100	99

5.2.5 Whole fleet imports

Advances to our modelling capabilities have given access to the underlying tight hour derating factor distributions. From this we have been able to extract percentiles to better understand the risk surrounding the mean annual values presented above.

Figure 30: Proportion of modelled tight hours where a maximum percentage of interconnected capacity is available for the Base Case



The percentiles show that the underlying tight hour derating factor distributions are in most cases bimodal with modes centred on zero and one hundred per cent (i.e. interconnectors are either exporting at full capacity or are at float). Percentile plots along with our insight are presented in Annex A.12.

The new view on to the "on-off" nature of interconnector flows raises the question of whether multiple markets have correlated periods when they are not exporting to GBR. The chart above shows for the Base case the proportion of modelled tight hours where a maximum percentage of total interconnected capacity is delivered. For example, 10% of the time, interconnector imports are less than or equal to approximately 40% of the total interconnector capacity. Alternatively, one can view the chart in terms of minimum capacity delivered. For example, we would expect total imports of over 67% of the total capacity for around 80% of the time if GB was in a stress period. This new insight has only become available following the improved model functionality implemented this year.

The further the curve lies towards the top left-hand corner of the chart, the greater the available capacity in tight hours. The steep ascent of the curve is therefore reasonably encouraging. However, note that this curve is derived from the Base case. As capacity in Europe is reduced in sensitivities, European markets will share more tight hours in which they are unable to export, and this will be reflected as lower availability of total interconnected capacity in a greater proportion of tight hours.

Summary

The interconnector de-rating factor ranges have been selected from the highest and lowest value from the results table for each country. The maximum is set by the European demand sensitivity in all cases except for Denmark where the maximum is set by the German coal sensitivity for the Base Case, Consumer Transformation and Leading the Way and the European Demand sensitivity for System Transformation and Falling Short. The minimum is set by either the French nuclear, Irish thermal or Norwegian hydro sensitivities.

It should be noted that while the events that may lead to a reduction in European demand and gas generating capacity are possible, the justifications for each of these sensitivities have little historical precedent. Therefore, the actual amount of demand or gas generating capacity removed from the scenarios to create the sensitivities is more speculative.

Ireland exhibits a particularly large range due to it being an isolated market when compared to the other markets. There is reasonably high capacity in Ireland, which results in excess capacity to supply GB. The Irish thermal sensitivity brings Ireland to its assumed LOLE standard (8 hours, which is high compared to markets with security standards based on LOLE). This results in a large reduction in thermal capacity in Ireland and therefore there is little spare capacity to export power to GB.

Norway exhibits a particularly low range owing to its large natural hydro capacity and high levels of interconnection.

The French sensitivity is the minimum sensitivity in all markets except for Ireland and Norway and generally gives derating factors of a few per cent below the European Gas sensitivity for Denmark and the Netherlands. The large reduction in French nuclear or European Gas generating capacity leads to similar shortfalls across continental Europe and therefore any excess capacity in Europe will be used primarily to meet any shortfalls on the continent before capacity is supplied to GB. This is due to GB being on the periphery of Europe and therefore tends to incur higher losses when importing power. The objective function of the modelling is to reduce load loss across the modelled markets in Europe and therefore supplying the markets which have the lowest loss access to spare capacity will be prioritised.

The modelled ranges do not include an allowance for interconnector import constraints in Great Britain, which we don't expect to be a material issue at winter peak. Adjustments for technical reliability will be made by BEIS. The ranges for each country are shown in Table 16. Although in some cases the ranges are wide, we consider them to be credible given the uncertainty on future generation capacity in Europe.

Lastly, new modelling capability has allowed access to the underlying distribution of derating factors in tight hours. We present percentile plots and relevant insight in Annex 12. Analysis shows that interconnector flow during stress periods is in most cases bimodal meaning that for the most part markets are either exporting at full capacity or not at all. For the Base case we have charted the proportion of modelled tight hours where a maximum percentage of total interconnected capacity is delivered. It should be noted that similar charts for downside sensitivities would show lower availability of total interconnected capacity in a greater proportion of tight hours.

Table 16: De-rating factor ranges by country for 2026/27

Country	Minimum	Maximum
Ireland	14	94
France	30	97
Belgium	31	95
Netherlands	51	92
Denmark	48	91
Norway	84	100

6. Results and Recommendation for T-1 Auction for 2023/24

Our recommendation for the target capacity for the T-1 auction for 2023/24 delivery is **5.8 GW**. Our modelling shows we expect this to a result in a Base Case LOLE of 0.4 hours, with indicative de-rated margin of 3.9 GW or 6.5% for winter 2023/24, broadly similar to what has been reported in recent Winter Outlook Reports[64]. The recommended capacity in this report will not necessarily be the capacity auctioned – this will be a decision for the Secretary of State. This value will be included in the Final Auction Guidelines published after pre-qualification.

This chapter presents the detailed modelling results to support our recommendation of 5.8 GW. Further information on potential capacity requirements in the period until 2036/37 can be found in Section 4.9.

6.1 Scenarios and Sensitivities to Model

The agreed scenarios and sensitivities to model were:

- Base Case (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Falling Short (FS)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Plant Availabilities (HIGH AVAIL)
- Low Plant Availabilities (LOW AVAIL)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON-DEL): Up to 6000 MW in 400 MW increments
- Over-Delivery (OVER DEL): Up to 2800 MW in 400 MW increments

6.2 Results

Table 17 shows the de-rated capacity required to meet the Reliability Standard of 3 hours LOLE for each scenario and sensitivity modelled. It also shows the amount of capacity outside of the CM (including previously contracted capacity), the total de-rated capacity and the ACS peak demand for each case.

All cases consider known non-delivery which is when capacity providers that secured an agreement covering delivery year 2023/24 from a previous auction can no longer meet their obligations. This known non-delivery totals 0.7 GW (de-rated) since the 2019 ECR (which contained our recommendation for the 2023/24 T-4 auction). We also assume additional non-delivery above the known non-delivery in the Base Case and FES scenarios. Non-delivery in the Base Case is our best view based on market intelligence of capacity

[64] https://www.nationalgrideso.com/document/212691/download

providers who we do not currently expect to meet their obligations. The Base Case assumes 1.1 GW of additional non-delivery for 2023/24. Non-delivery in the FES scenarios reflect uncertainty of capacity providers that may be at risk of not meeting their obligations. There is 0.9 GW of additional non-delivery assumed in the CT and ST scenarios, the FS scenario assumes 1.5 GW of additional non-delivery, and the LW scenario assumes an additional 1.6 GW non-delivery for 2023/24. This can be seen in Table 17 where the previously contracted capacity for these scenarios is either above or below the Base Case value.

Furthermore, all scenarios and sensitivities include 0.4 GW over-delivery for 2023/24 based on the outcome of a development project addressing recommendation 54 from the 2020 PTE report. This is eligible capacity assumed to stay open without a CM agreement or secondary trade – this has been modelled by increasing the non-CM autogeneration de-rated capacity by 0.4 GW. This project (see Section 2.5.2 of the 2021 ECR) recommended that a small amount of over-delivery is likely to materialise for the T-1 year and therefore could be assumed in the Base Case (and scenarios). Further over-delivery is possible but less certain and has been modelled via over-delivery sensitivities.

The results reflect our latest view of de-rating factors and Transmission Entry Capacity (TEC) values for CM units. Two changes in particular are worth highlighting. Firstly, the de-rating factors for duration limited storage have been revised since the T-4 auction for 2020/21 such that the de-rating factors now reflect the duration capability of storage providers. As a result, our estimate of the de-rated capacity of duration limited storage awarded multi-year agreements from CM auctions, including the T-4 auction for 2020/21, is now around 0.4 GW lower than has been contracted (which was also noted in the 2019 ECR[65] that contained our capacity to secure recommendation for the 2023/24 T-4 auction). Secondly, we model all transmission connected units using the latest values for technology de-rating factors and Transmission Entry Capacity (TEC). This results in a de-rated capacity that is 0.7 GW lower than was previously contracted. These two changes combined with the known non-delivery (0.7 GW) and assumed non-delivery (1.1 GW) have effectively reduced the estimate of the previously contracted capacity for 2023/24 in the Base Case from the reported[66] figure of around 48.9 GW to around 46.0 GW – a shortfall of 2.9 GW that needs to be secured again, an increase of 2.5 GW compared to the 2019 ECR.

[65] https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf
[66] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20DY%2025-26%20Final%20Auction%20Results%20Report%20V1.0.pdf

Table 17: Modelled de-rated capacities and peak demands – 2023/24

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW) in sensitivity	Total derated capacity (GW)	ACS Peak (GW)
Leading the Way	LW	-2.8	57.2	45.5	0.0	54.4	52.5
Warm Winter	BC_WARM	-0.1	59.1	46.0	0.0	59.0	58.5
Over Delivery Sensitivity: 2800	BC_OVER_DEL_2800	0.2	61.6	46*	2.8	61.7	58.5
Consumer Transformation	CT	0.5	58.7	46.2	0.0	59.2	56.8
Over Delivery Sensitivity: 2400	BC_OVER_DEL_2400	0.6	61.2	46*	2.4	61.7	58.5
Over Delivery Sensitivity: 2000	BC_OVER_DEL_2000	1.0	60.8	46*	2.0	61.7	58.5
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	1.4	60.4	46*	1.6	61.7	58.5
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	1.8	60.0	46*	1.2	61.7	58.5
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	2.2	59.6	46*	0.8	61.7	58.5
High Availability	BC_HIGH_AVAIL	2.4	59.2	46.5	0.0	61.5	58.5
Low Demand	BC_LOW_DEMAND	2.4	58.7	46.0	0.0	61.1	57.9
System Transformation	ST	2.6	58.8	46.2	0.0	61.3	58.3
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	2.6	59.2	46*	0.4	61.7	58.5
Base Case	BC	3.0	58.8	46.0	0.0	61.7	58.5
Non Delivery Sensitivity: -400	BC_NON_DEL_400	3.4	58.4	46*	-0.4	61.7	58.5
Non Delivery Sensitivity: -800	BC_NON_DEL_800	3.8	58.0	46*	-0.8	61.7	58.5
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	4.2	57.6	46*	-1.2	61.7	58.5
Cold Winter	BC_COLD	4.3	58.2	46.0	0.0	62.5	58.5
Low Availability	BC_LOW_AVAIL	4.3	57.6	44.8	0.0	61.9	58.5
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	4.6	57.2	46*	-1.6	61.7	58.5
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	5.0	56.8	46*	-2.0	61.7	58.5
High Demand	BC_HIGH_DEMAND	5.1	58.7	46.0	0.0	63.8	60.7
Falling Short	FS	5.2	58.3	45.6	0.0	63.6	61.0
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	5.4	56.4	46*	-2.4	61.7	58.5
Non Delivery Sensitivity: -2800	BC_NON_DEL_2800	5.8	56.0	46*	-2.8	61.7	58.5
Non Delivery Sensitivity: -3200	BC_NON_DEL_3200	6.2	55.6	46*	-3.2	61.7	58.5
Non Delivery Sensitivity: -3600	BC_NON_DEL_3600	6.6	55.2	46*	-3.6	61.7	58.5
Non Delivery Sensitivity: -4000	BC_NON_DEL_4000	7.0	54.8	46*	-4.0	61.7	58.5
Non Delivery Sensitivity: -4400	BC_NON_DEL_4400	7.4	54.4	46*	-4.4	61.7	58.5
Non Delivery Sensitivity: -4800	BC_NON_DEL_4800	7.8	54.0	46*	-4.8	61.7	58.5
Non Delivery Sensitivity: -5200	BC_NON_DEL_5200	8.2	53.6	46*	-5.2	61.7	58.5
Non Delivery Sensitivity: -5600	BC_NON_DEL_5600	8.6	53.2	46*	-5.6	61.7	58.5
Non Delivery Sensitivity: -6000	BC_NON_DEL_6000	9.0	52.8	46*	-6.0	61.7	58.5

** The previously contracted capacity figure assumes full delivery. Any over or non-delivery would be split between plants contracted in previous auctions and plants contracted in future auctions. As such this is accounted for in a separate column.*

N.B Total derated capacity (GW) = Capacity to Secure (GW) + Outside Capacity Market (GW). ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts covering 2023/24 that were awarded in previous auctions. This capacity is included in the 'Outside CM' capacity and is shown in a separate column. Note that the non-delivery & over-delivery sensitivities have been modelled by reducing and increasing the 'Outside CM' capacity respectively.

The LW scenario and 6.0 GW non-delivery sensitivities define the extremes of the capacity to secure range for 2023/24 (-2.8 GW to 9.0 GW). In the LW scenario and Warm Winter sensitivity, the capacity to secure is negative indicating that sufficient capacity has already been secured in previous actions to meet the 3 hours LOLE Reliability Standard.

6.3 Recommended Capacity to Secure

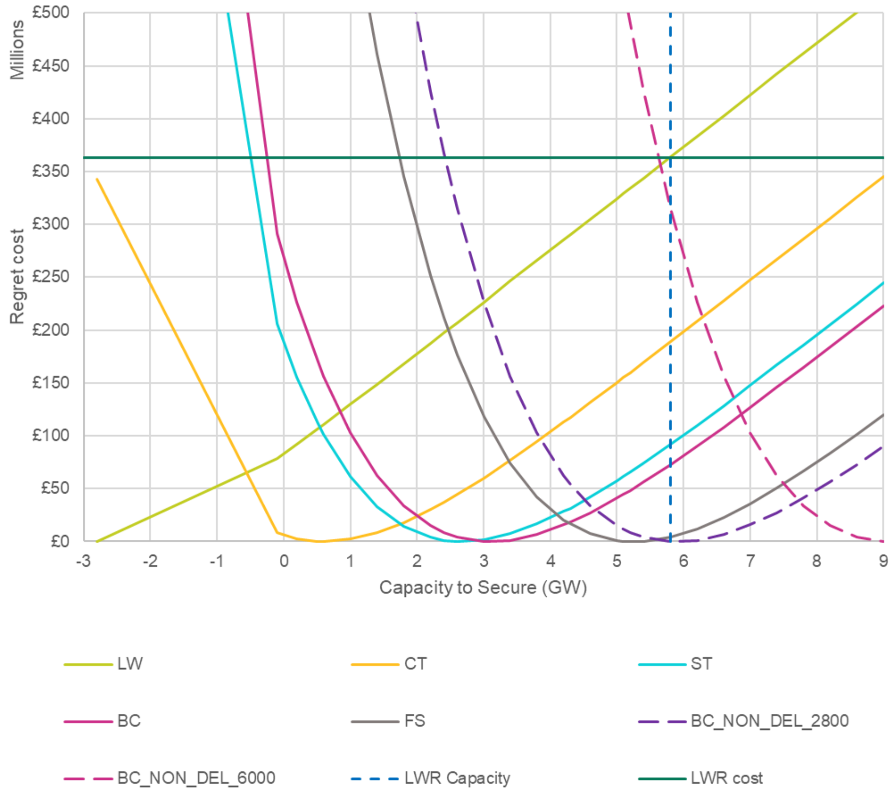
The results in Table 17 show there is a wide range in the capacity required to meet 3 hours LOLE from -2.8 GW to 9.0 GW. If we knew which case would actually occur in 2023/24, then we could simply recommend the capacity associated with this case as the optimal target capacity. However, we do not know what will happen in 2023/24. This means that if we were to pick a capacity to secure from one of the values listed in Table 17 then there is a high risk that this will not be the one associated with what happens. This could mean that we secure too much capacity resulting in a LOLE below 3 hours or that we secure too little capacity resulting in a LOLE above 3 hours. In either case, the total cost is non-optimal as either the cost of capacity is higher than needed or the cost of unserved energy is higher than expected for a LOLE of 3 hours.

We use the Least Worst Regret (LWR) methodology to select one of the values from Table 17 as our recommended target capacity for the T-1 auction for 2023/24. The LWR methodology considers the total cost for each case in the event that any one of the other cases actually happens (i.e. it assesses all potential options for over- or under-securing capacity). For each case in Table 17, there will be a worst-case outcome. For example. if we select the option needing 9.0 GW then the worst-case outcome would be if -2.8 GW was actually needed. The LWR[67] calculates the cost for the worst-case outcome in each case and selects the case whose worst-case outcome has the lowest cost. The LWR assumes a net CONE of £49/kW/year and an energy unserved cost (or value of lost load) of £17,000/MWh, which is consistent with the Government's Reliability Standard. This means that our recommended target capacity based on the LWR outcome corresponds to the value on the CM demand curve for the net CONE capacity cost. The clearing price in the auction may be different to net CONE, resulting in the cleared capacity being different to the target capacity. Further information on the LWR methodology is provided in the Annex A.8.

The outcome of the LWR calculation is a recommended capacity to secure of **5.8 GW**. This is the capacity associated with the 2.8 GW non-delivery sensitivity. This outcome excludes any capacity secured for 2023/24 in earlier auctions assumed in the Base Case.

The chart in Figure 31 shows the regret costs for the two cases that define the extremes of the LWR range (LW and the 6 GW non-delivery sensitivity), the other FES and Base Case and the 2.8 GW non-delivery sensitivity that sets the LWR outcome. The LWR capacity outcome and LWR cost are also shown. The LWR outcome is the closest capacity requirement value to the capacity that marks the intersection of the regret costs for the two cases at the extremes of the LWR range (LW and the 6 GW non-delivery sensitivity).

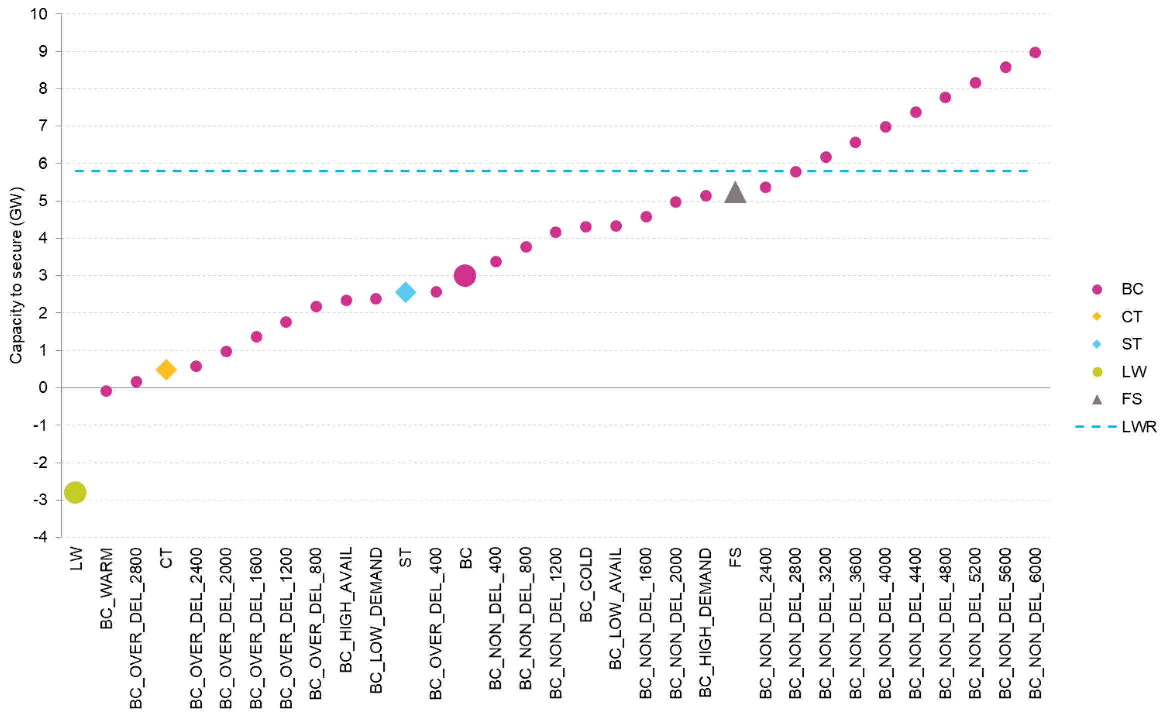
Figure 31: Regret Costs for scenarios and selected sensitivities – 2023/24



[67] If the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR).

Figure 32 illustrates the full range of potential capacity requirements and identifies the LWR outcome (5.8 GW). Scenarios are highlighted with larger markers and each scenario and sensitivity is colour coded. The Falling Short scenario has a higher requirement than the other scenarios, mainly due to a higher peak demand. The Leading the Way scenario has a lower requirement due to a much lower peak demand.

Figure 32: LWR outcome and other cases modelled comparison – 2023/24



N.B. The points on this chart represent the de-rated capacity required for each scenario / sensitivity to meet the Reliability Standard of 3 hours LOLE.

6.3.1 Covered range

We consider that a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity was to occur in 2023/24 that is not covered, then the LOLE could be greater than 3 hours. This could mean mitigating actions (e.g. voltage reduction, max gen. service and emergency assistance from interconnectors) are deployed more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections. Figure 32 shows that the outcome of the LWR calculation covers 25 of the 33 cases.

6.3.2 Adjustments to Target Capacity

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State. This value will be included in the Final Auction Guidelines published after pre-qualification. To obtain the final T-1 auction target, a number of adjustments to the recommended value may need to be made (e.g. denoted by ***v***, ***x***, ***y*** and ***z*** below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in ***z***):

- Capacity with Long Term STOR contracts. In previous auctions, long term STOR units that chose not to surrender their contracts were excluded from the CM and an adjustment made. Although these providers are now eligible for CM agreements, if they opt out of prequalification and are assumed to be operational in 2023/24, an adjustment may still be required – ***v*** GW.
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine DSR to opt out but remain operational – ***x*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – ***y*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to contracted plants with different closure assumptions to the Base Case – ***z*** GW.*

Therefore, the recommended capacity to secure through the 2023/24 T-1 auction could be:

- 5.8 GW - ***v*** - ***x*** - ***y*** - ***z***.

*National Grid ESO's modelling assumes no eligible generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process.

6.3.3 Comparison with T-4 for 2023/24 recommendation

In our 2019 ECR[68], we recommended a capacity to secure for 2023/24 of 44.7 GW derived from the cold winter sensitivity. Of this, the Secretary of State held back 1.2 GW for the T-1 auction for 2023/24 leaving an initial target capacity of 43.5 GW for the T-4 auction. Following pre-qualification and the conclusion of the T-3 auction for 2022/23, the target for 2023/24 delivery was reduced by the Secretary of State to 43.1 GW with no changes to the 1.2 GW originally set aside for the T-1 auction for 2023/24. The 0.4 GW (net) of adjustments made to the T-4 auction for 2023/24 target comprised of:

- 0.2 GW reduction due to capacity from the 2022/23 T-3 auction awarded multi-year agreements covering 2023/24
- 0.3 GW reduction relating to long-term STOR outside of the CM.
- 0.1 GW increase due to autogeneration assumed to be outside of the CM participating in prequalification.

In general, when compared to the analysis for 2023/24 in the 2019 ECR that ultimately led to the 1.2 GW set aside by the Secretary of State for the T-1 auction, the 2022 ECR LWR outcome for 2023/24 is 4.6 GW higher than the 1.2 GW set aside. This difference is the result of the following increases and decreases.

[68] Normally in the ECR we compare the T-1 recommendation to the previous T-4 recommendation. However, the 2022/23 T-4 auction was not held as the Capacity Market was suspended. The 2022/23 T-4 auction was replaced by a 2022/23 T-3 auction. Hence we make the comparison to the 2022/23 T-3 recommendation set out in the 2019 ECR.

The increases total 6.2 GW:

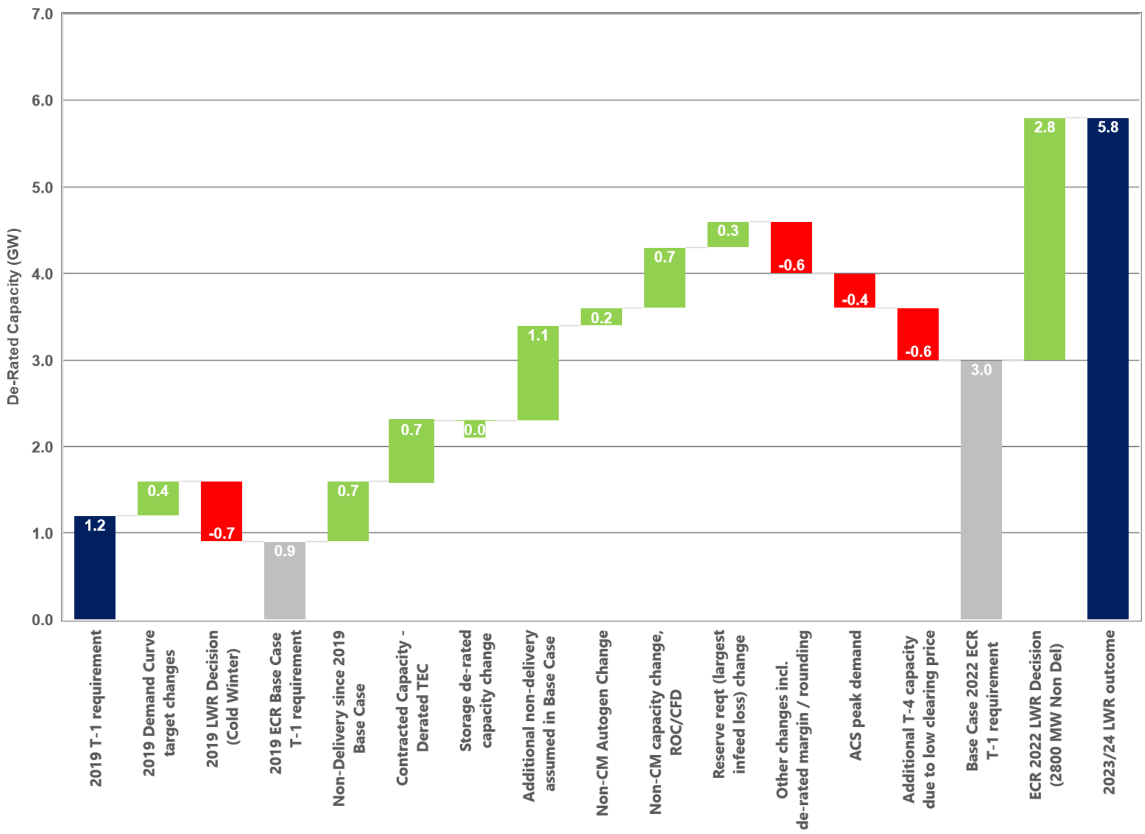
- 0.4 GW net increase relating to the demand curve adjustments made in 2019 following prequalification for the T-4 auction (see above for more details). These adjustments are no longer relevant for the T-1 auction as the prequalification for the T-1 auction has not yet taken place and the 2022 Base Case generation assumptions are different to the 2019 Base Case assumptions.
- Non-delivery since the 2019 Base Case, totalling 0.7 GW in 2023/24 (this is the known non-delivery - see Section 6.2).
- The contracted conventional capacity for 2023/24 from previous auctions being 0.7 GW greater than the de-rated TEC (see Section 6.2). Note that there was no change in estimated de-rated storage awarded multi-year contracts from the 2020/21 T-4 auction onwards (0.4 GW reduction in the 2022 ECR compared to a 0.4 GW reduction in the 2019 ECR for 2023/24).
- An increase of 1.1 GW due to additional non-delivery assumed in the Base Case based on market intelligence of capacity providers who we do not currently expect to meet their obligations for 2023/24.
- An increase of 0.2 GW relating to lower levels of assumed opted-out or ineligible (below 1 MW) autogeneration than the 2019 Base Case. Note that the non-CM autogeneration in the 2022 ECR includes the 0.4 GW over-delivery assumed in the Base Case (see Section 6.2)
- A 0.7 GW increase resulting from lower non-CM renewable capacity (see Table 22 for breakdown). This is largely comprised of lower contributions at peak from wind, biomass, landfill gas and from other small-scale capacity.
- A 0.3 GW increase in reserve for largest infeed loss compared to the 2019 Base Case.
- A change in the scenarios and sensitivities modelled resulting in the net LWR outcome difference from the Base Case being 2.1 GW higher (2.8 GW non-delivery compared to 0.7 GW difference from cold winter). In the 2019 ECR, the recommended capacity to secure corresponded to a LOLE for the Base Case of 2.0 hours whereas in the 2022 ECR, the recommended capacity to secure corresponds with a lower LOLE for the Base Case of 0.4 hours (see Section 6.3.5).

The decreases total 1.6 GW:

- A 0.6 GW reduction due to other changes (change in de-rated margin required for 3 hours LOLE compared to the 2019 Base Case and rounding).
- A 0.4 GW reduction due to a lower peak demand in 2023/24 compared to the 2019 Base Case (see section on peak demand changes below).
- A reduction in requirement from over-securing in the T-4 auction for 2023/24 by 0.6 GW due to a low clearing price.

The following waterfall chart, Figure 33, shows how the original 1.2 GW set aside for the T-1 auction for 2023/24 (derived from the 2019 cold winter sensitivity) has changed into a LWR outcome of 5.8 GW (derived from the 2022 Base Case 2.8 GW non-delivery sensitivity) as a result of the 4.6 GW net increase described above.

Figure 33: Comparison with original T-1 requirement for 2022/23 (de-rated)



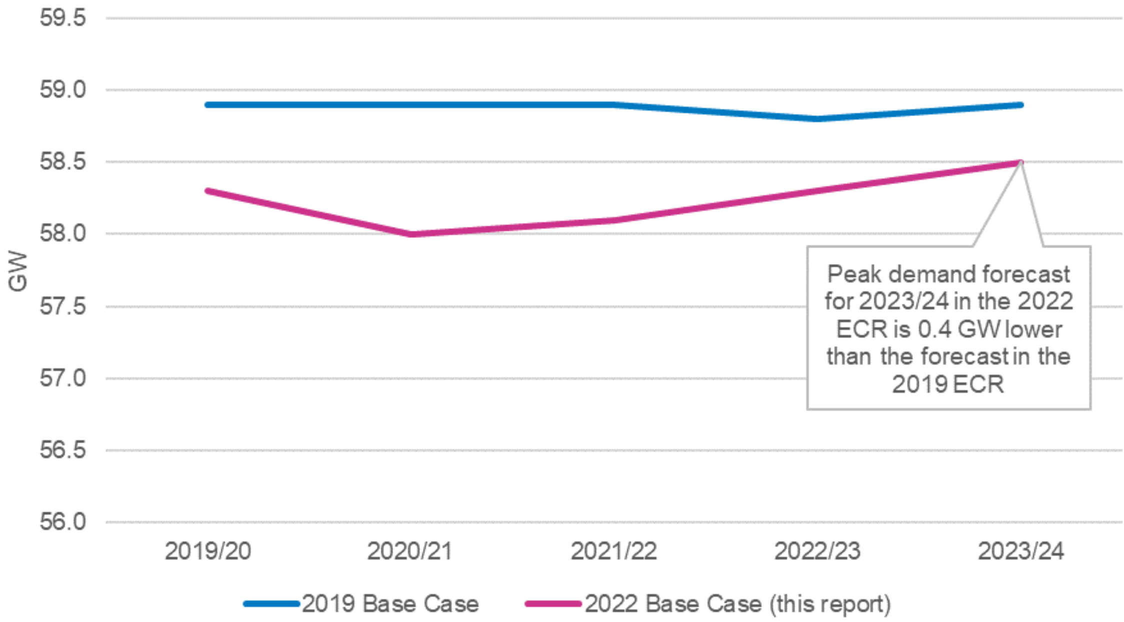
Note: intermediate totals in grey above show requirements for 2019 Base Case and 2022 Base Case

As highlighted above, since the 2019 ECR, the peak demand for 2023/24 has reduced slightly by 0.4 GW (from 58.9 GW to 58.5 GW). Figure 34 compares the underlying ACS peak demand in the 2022 Base Case (2022 BC) to the underlying ACS peak demand in the 2019 Base Case (2019 BC) over the period from 2019/20 to 2023/24. The 2022 Base Case peak demand forecast for 2023/24 is slightly below but still very close to the 2019 Base Case. There are several factors affecting energy demand since 2019, but we have seen the peak ACS demand remaining fairly constant.

The letter[69] written to Ofgem under Special Condition 4L.13 gives an explanation of how we are developing our demand forecasting methodology and the steps taken to taken to improve the peak demand forecast.

[69] To be published at the same time as the ECR at https://www.emrdeliverybody.com/cm/home.aspx
The letter published in 2019 is available at
https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Demand%20Incentive%20Letter%202019.pdf

Figure 34: Peak Demand Comparison (2022 ECR v 2019 ECR)



6.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over-delivery (OD) sensitivities, a question was raised around how sensitive the LWR outcome was to the sensitivities included, e.g. maximum level of non-delivery; a sensitive outcome is one that would change every time the included sensitivities changed. To address this, we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 18.

Table 18: Sensitivity of T-1 LWR outcome to scenarios / sensitivities included in LWR

Sensitivities added or removed	2023/24 outcome
Standard range	5.8
Include additional 3.2 GW over-delivery sensitivity	5.8
Remove Leading the Way scenario	6.2
Remove 6.0 GW non-delivery sensitivity	5.4
Include additional 6.4 GW non-delivery sensitivity	6.2

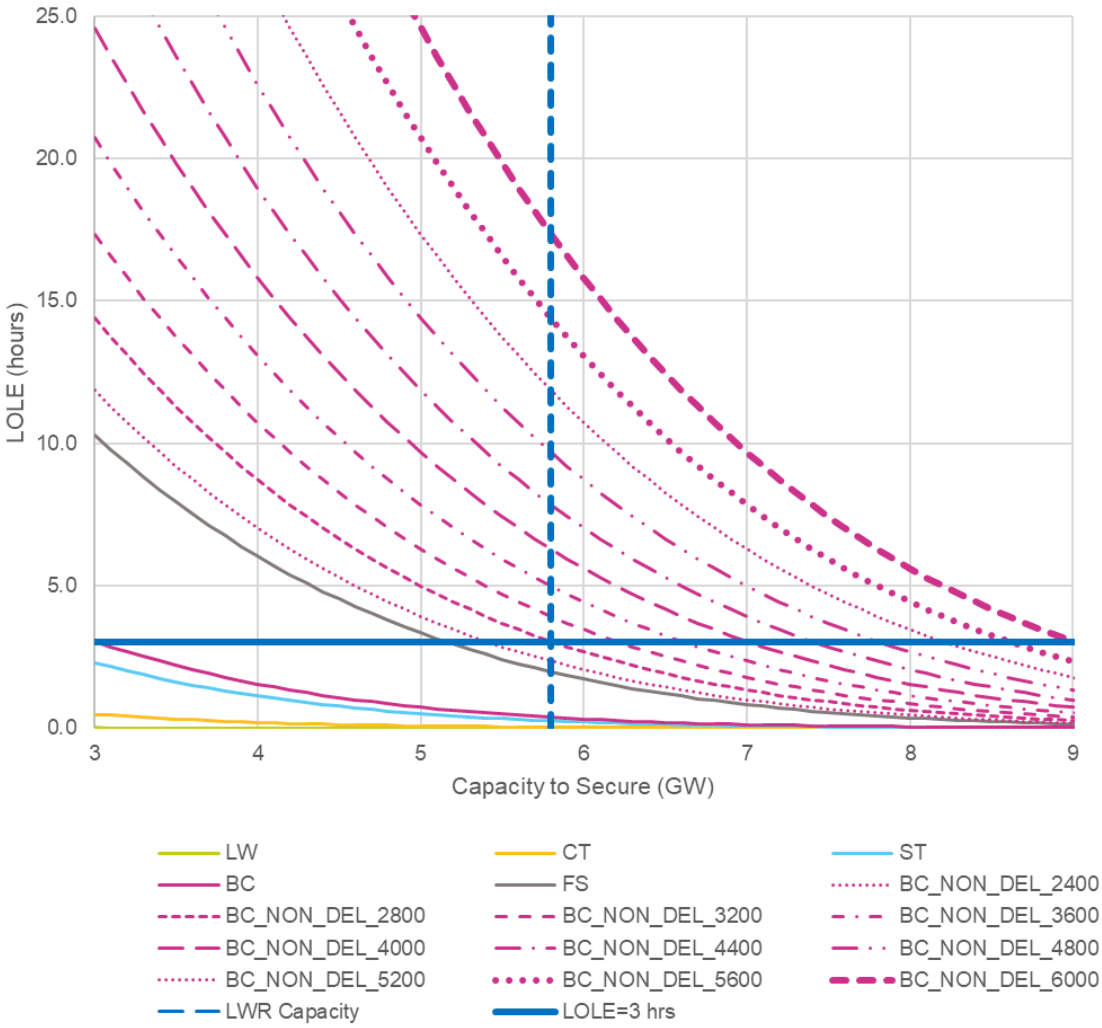
Removing the lowest target capacity case (Leading the Way) increases the LWR outcome by 0.4 GW. Adding a higher target capacity case (6.4 GW non-delivery) also increases the LWR outcome by 0.4 GW. Removing the highest case currently in the LWR range (6.0 GW non-delivery) reduces the LWR outcome by 0.4 GW. No other single cases affect the LWR outcome. For example, adding additional over-delivery cases has no impact on the LWR outcome as the requirement of the LW scenario is below the requirements of the over-delivery cases.

We consider the outcome of the LWR calculation to be suitably robust and that the choice of scenarios and sensitivities included are well-justified as set out in Chapter 4.

6.3.5 Sensitivity of LOLE to T-1 Capacity to Secure

To help decision makers to understand the sensitivity of LOLE to the target capacity chosen for the T-1 auction, we have included Figure 35 which illustrates how the LOLE for the scenarios and highest non-delivery sensitivities varies with capacity to secure. We have not included all of the sensitivities on the chart to avoid overcrowding but the other sensitivities have LOLE values below the non-delivery sensitivities shown (the values for all scenarios and sensitivities are in the ECR Data Workbook). As can be seen, reducing the capacity to secure to 5.2 GW would mean that the LOLE for the FS scenario and the non-delivery sensitivities shown would be at 3 hours or above and increasing the capacity to secure to 6.6 GW would keep the LOLE around 3 hours or below for the non-delivery sensitivities with non-delivery values of 3.6 GW or below. The LOLE for the Base Case is 0.4 hours for the recommended capacity to secure (5.8 GW) – this would increase to 0.6 hours for a capacity to secure of 5.2 GW and reduce to 0.2 hours for a capacity to secure of 6.6 GW.

Figure 35: Sensitivity of LOLE to Capacity to Secure – 2023/24



7. Results and Recommendation for T-4 Auction for 2026/27

Our recommendation for the target capacity for the T-4 auction for 2026/27 delivery is **43.9 GW**. Our modelling shows we expect this to a result in a Base Case LOLE of 0.3 hours, with indicative de-rated margin of 3.8 GW or 6.1% for winter 2026/27, broadly similar to what has been reported in recent Winter Outlook Reports[70]. The recommended capacity in this report will not necessarily be the capacity auctioned – this will be a decision for the Secretary of State. This value will be included in the Final Auction Guidelines published after pre-qualification.

This chapter presents the detailed modelling results to support our recommendation of 43.9 GW. Further information on capacity requirements in years out to 2036/37 can be found in Section 4.9.

7.1 Sensitivities to model

The agreed scenarios and sensitivities to model were:

- Base Case (BC)
- FES Consumer Transformation (CT)
- FES System Transformation (ST)
- FES Leading the Way (LW)
- FES Falling Short (FS)
- Cold Weather Winter (COLD)
- Warm Weather Winter (WARM)
- High Demand (HIGH DEMAND)
- Low Demand (LOW DEMAND)
- Non-Delivery (NON-DEL): Up to 6800 MW in 400 MW increments
- Over-Delivery (OVER DEL): Up to 3600 MW in 400 MW increments

7.2 Results

Table 19 shows the de-rated capacity required to meet the Reliability Standard of 3 hours LOLE for each scenario and sensitivity modelled. It also shows the capacity outside of the CM (including previously contracted capacity), the total de-rated capacity and the ACS peak demand for each case.

All cases consider known non-delivery where capacity providers that secured an agreement covering delivery year 2026/27 from a previous auction can no longer meet their obligations. This known non-delivery totals around 0.6 GW (de-rated) since the 2021 ECR. In addition, we also assume non-delivery in the Base Case and FES scenarios. Non-delivery in the Base Case is our best view based on market intelligence of capacity providers who we do not currently expect to meet their obligations. The Base Case assumes 0.1 GW of additional

[70] https://www.nationalgrideso.com/document/212691/download

non-delivery for 2026/27. Non-delivery in the FES scenarios reflect uncertainty of capacity providers that may be at risk of not meeting their obligations. There is no additional non-delivery assumed in the CT scenario, the ST and FS scenarios assume the same additional non-delivery as the Base Case (0.1 GW), and the LW scenario assumes an additional 0.5 GW non-delivery for 2026/27.

The results also reflect our latest view of de-rating factors and TEC values for CM units as we described in Section 6.2. In particular, our estimate of the de-rated capacity of duration limited storage awarded multi-year agreements covering 2026/27 from previous CM auctions, is now around 0.9 GW lower than has been contracted. This change combined with the known non-delivery (0.6 GW) and assumed non-delivery (0.1 GW) have effectively reduced the estimate of the previously contracted capacity for 2026/27 in the Base Case from the reported[71] figure of 10.3 GW to 8.7 GW – a shortfall of 1.6 GW that needs to be secured again.

Table 19: Modelled de-rated capacities and peak demands - 2026/27

Name	Graph Code	Capacity to Secure (GW)	Outside CM (GW)	Previously Contracted Capacity (GW)	Over Or Non Delivery (GW) in sensitivity	Total derated capacity (GW)	ACS Peak (GW)
Leading the Way	LW	33.3	25.2	8.3	0.0	58.5	53.7
Over Delivery Sensitivity: 3600	BC_OVER_DEL_3600	37.1	26.4	8.7*	3.6	63.6	60.5
Warm Winter	BC_WARM	37.5	23.7	8.8	0.0	61.2	60.5
Over Delivery Sensitivity: 3200	BC_OVER_DEL_3200	37.5	26.0	8.7*	3.2	63.6	60.5
Over Delivery Sensitivity: 2800	BC_OVER_DEL_2800	37.9	25.6	8.7*	2.8	63.6	60.5
Over Delivery Sensitivity: 2400	BC_OVER_DEL_2400	38.3	25.2	8.7*	2.4	63.6	60.5
Over Delivery Sensitivity: 2000	BC_OVER_DEL_2000	38.7	24.8	8.7*	2.0	63.6	60.5
Over Delivery Sensitivity: 1600	BC_OVER_DEL_1600	39.1	24.4	8.7*	1.6	63.6	60.5
Consumer Transformation	CT	39.3	23.4	8.8	0.0	62.7	59.0
Over Delivery Sensitivity: 1200	BC_OVER_DEL_1200	39.5	24.0	8.7*	1.2	63.6	60.5
Low Demand	BC_LOW_DEMAND	39.8	22.9	8.7	0.0	62.7	59.5
Over Delivery Sensitivity: 800	BC_OVER_DEL_800	39.9	23.6	8.7*	0.8	63.6	60.5
System Transformation	ST	40.0	22.8	8.7	0.0	62.7	59.5
Over Delivery Sensitivity: 400	BC_OVER_DEL_400	40.3	23.2	8.7*	0.4	63.6	60.5
Base Case	BC	40.7	22.8	8.7	0.0	63.6	60.5
Non Delivery Sensitivity: -400	BC_NON_DEL_400	41.1	22.4	8.7*	-0.4	63.6	60.5
Non Delivery Sensitivity: -800	BC_NON_DEL_800	41.5	22.0	8.7*	-0.8	63.6	60.5
Non Delivery Sensitivity: -1200	BC_NON_DEL_1200	41.9	21.6	8.7*	-1.2	63.6	60.5
Cold Winter	BC_COLD	41.9	22.4	8.7	0.0	64.3	60.5
High Demand	BC_HIGH_DEMAND	42.2	22.9	8.7	0.0	65.1	62.1
Non Delivery Sensitivity: -1600	BC_NON_DEL_1600	42.3	21.2	8.7*	-1.6	63.6	60.5
Non Delivery Sensitivity: -2000	BC_NON_DEL_2000	42.7	20.8	8.7*	-2.0	63.6	60.5
Non Delivery Sensitivity: -2400	BC_NON_DEL_2400	43.1	20.4	8.7*	-2.4	63.6	60.5
Non Delivery Sensitivity: -2800	BC_NON_DEL_2800	43.5	20.0	8.7*	-2.8	63.6	60.5
Non Delivery Sensitivity: -3200	BC_NON_DEL_3200	43.9	19.6	8.7*	-3.2	63.6	60.5
Non Delivery Sensitivity: -3600	BC_NON_DEL_3600	44.3	19.2	8.7*	-3.6	63.6	60.5
Falling Short	FS	44.4	22.1	8.7	0.0	66.5	63.4
Non Delivery Sensitivity: -4000	BC_NON_DEL_4000	44.7	18.8	8.7*	-4.0	63.6	60.5
Non Delivery Sensitivity: -4400	BC_NON_DEL_4400	45.1	18.4	8.7*	-4.4	63.6	60.5
Non Delivery Sensitivity: -4800	BC_NON_DEL_4800	45.5	18.0	8.7*	-4.8	63.6	60.5
Non Delivery Sensitivity: -5200	BC_NON_DEL_5200	45.9	17.6	8.7*	-5.2	63.6	60.5
Non Delivery Sensitivity: -5600	BC_NON_DEL_5600	46.3	17.2	8.7*	-5.6	63.6	60.5
Non Delivery Sensitivity: -6000	BC_NON_DEL_6000	46.7	16.8	8.7*	-6.0	63.6	60.5
Non Delivery Sensitivity: -6400	BC_NON_DEL_6400	47.1	16.4	8.7*	-6.4	63.6	60.5
Non Delivery Sensitivity: -6800	BC_NON_DEL_6800	47.5	16.0	8.7*	-6.8	63.6	60.5

** The previously contracted capacity figure assumes full delivery. Any over or non-delivery would be split between plants contracted in previous auctions and plants contracted in future auctions. As such this is accounted for in a separate column*

N.B Total derated capacity (GW) = Capacity to Secure (GW) + Outside Capacity Market (GW). ACS Peak demand excludes reserve for largest infeed loss. Capacity to secure excludes any capacity assumed in the modelling with contracts covering 2026/27 that were awarded in previous auctions. This capacity is included in the 'Outside CM' capacity and is shown in a separate column. Note that the non-delivery & over-delivery sensitivities have been modelled by reducing and increasing the 'Outside CM' capacity respectively.

[71] See page 5 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/T-4%20DY%2025-26%20Final%20Auction%20Results%20Report%20V1.0.pdf

7.3 Recommended Capacity to Secure

Table 19 shows there is a wide range in the capacity required to meet 3 hours LOLE from 33.3 GW to 47.5 GW. The LW scenario and 6.8 GW non-delivery sensitivities define the extremes of the range. We use the Least Worst Regret (LWR) methodology described in Section 6.3 to select one of the values from Table 19 as our recommended target capacity for the 2026/27 T-4 auction.

The outcome of the LWR calculation is a capacity to secure of **43.9 GW**. This is the capacity associated with the 3.2 GW non-delivery sensitivity. This outcome excludes any capacity secured for 2026/27 in earlier auctions assumed in the Base Case.

The chart in Figure 36 shows the regret costs for the two cases that define the extremes of the LWR range (LW and the 6.8 GW non-delivery sensitivity), the other FES and Base Case and the 3.2 GW non-delivery sensitivity that sets the LWR outcome. The LWR capacity outcome and LWR cost are also shown. The LWR outcome is the closest capacity requirement value to the capacity that marks the intersection of the regret costs for the two cases at the extremes of the LWR range (LW and the 6.8 GW non-delivery sensitivity).

Figure 36: Regret Costs for scenarios and selected sensitivities – 2026/27

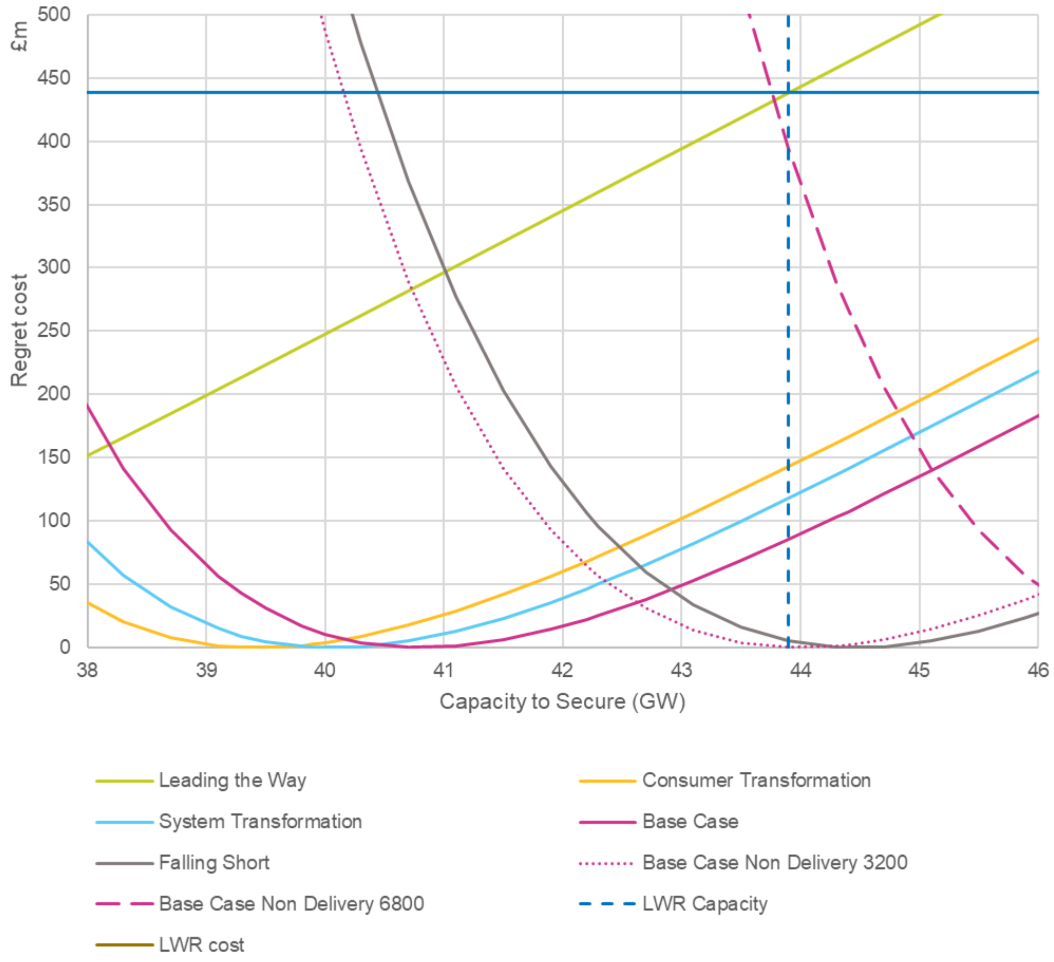
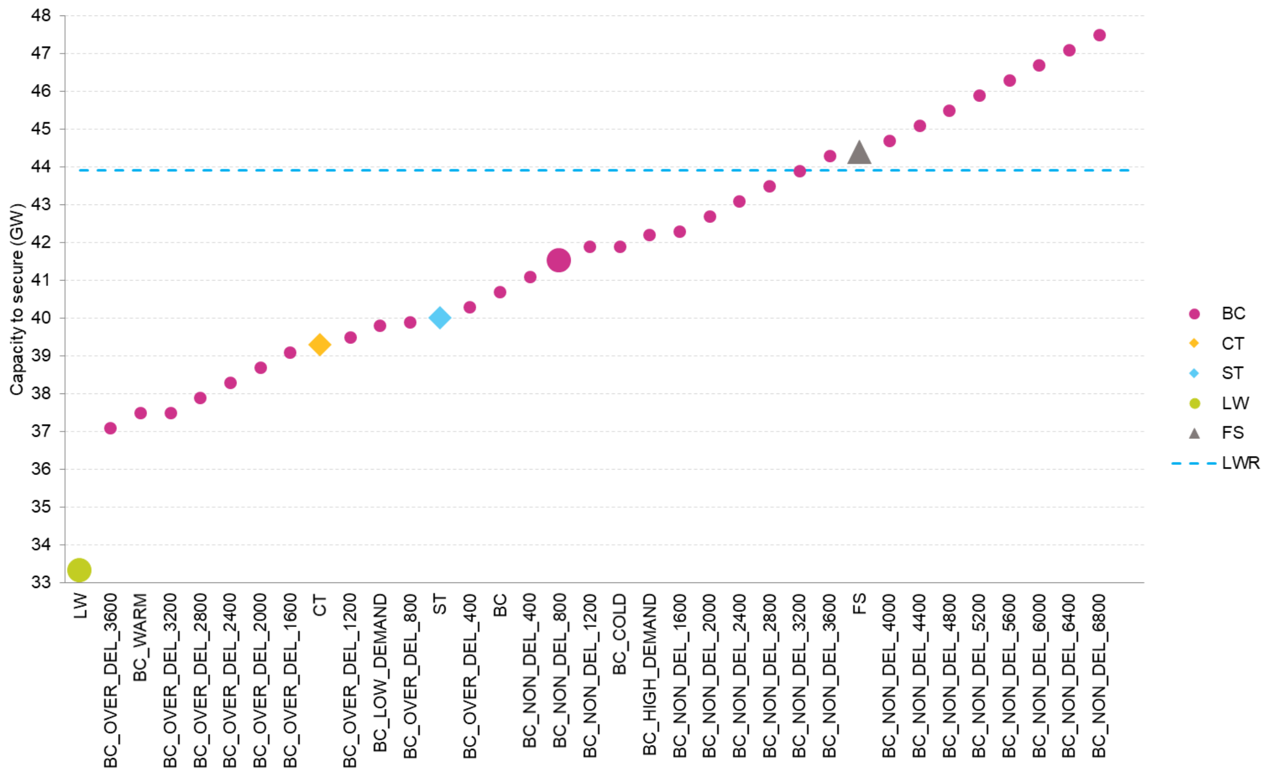


Figure 37 illustrates the full range of potential capacity requirements and identifies the LWR outcome (43.9 GW). The Falling Short scenario has a higher requirement than the other scenarios, mainly due to a higher peak demand and the Leading the Way scenario a lower requirement due to a much lower peak demand.

Figure 37: LWR outcome and other cases modelled comparison – 2026/27



N.B. The points on this chart represent the de-rated capacity required for each scenario / sensitivity to meet the Reliability Standard of 3 hours LOLE.

7.3.1 Covered range

We consider that a scenario or sensitivity is covered by the capacity secured if the LOLE is at or below the Reliability Standard of 3 hours per year. If a scenario or sensitivity was to occur in 2026/27 that is not covered, then the LOLE could be greater than 3 hours. This could mean mitigating actions (e.g. voltage reduction, max gen. service and emergency assistance from interconnectors) are deployed more frequently and/or in higher volumes to reduce the risk of any controlled disconnections. If the loss of load is higher than the level of mitigating actions, this may lead to controlled customer disconnections. The outcome of the LWR calculation covers 25 of the 35 cases as shown in Figure 37.

7.3.2 Adjustments to Recommended Capacity

The recommended capacity in this report will not necessarily be the capacity auctioned - this will be a decision for the Secretary of State. This value will be included in the Final Auction Guidelines published after pre-qualification. To obtain the capacity auction requirement, a number of adjustments to the recommended figure will need to be made (e.g. denoted by ***v***, ***w***, ***x***, ***y*** and ***z*** below) including a potential adjustment to the previously contracted capacity assumed in the modelling (in ***z***):

- Capacity with Long Term STOR contracts. In previous auctions, long term STOR units that chose not to surrender their contracts were excluded from the CM and an adjustment made. Although these providers are now eligible for CM agreements, if they opt out of prequalification and are assumed to be operational in 2026/27, an adjustment may still be required – ***v*** GW
- Government (upon confirming auction parameters to National Grid ESO prior to auction guidelines) will determine how much capacity to hold back for the T-1 auction for 2026/27 – ***w*** GW.
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine DSR to opt-out but remain operational – ***x*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine distributed generation to opt out but remain operational – ***y*** GW.*
- Government (either upon confirming auction parameters to National Grid ESO prior to auction guidelines or post pre-qualification) will determine large scale generation to opt out but remain operational or adjustment due to previously contracted plants with different closure assumptions to the Base Case – ***z*** GW.*

Therefore, the recommended capacity to secure through the T-4 auction for 2026/27 could be:

- 43.9 GW - ***v*** - ***w*** - ***x*** - ***y*** - ***z***.

* National Grid ESO's modelling assumes no eligible generation or DSR opts out as no data is currently available to inform the modelling process but will hopefully become available through the pre-qualification process.

The auction will select from a range of capacity levels depending on the demand curve, determined by the Government, and the cost of capacity which enters the auction.

Given that it is unlikely that the marginal capacity in the auction will result in an LOLE of exactly 3 hours, the demand curve for the auction will result in a capacity from a range around the target capacity. Thus, a recommended de-rated capacity of 43.9 GW could result in a differing capacity volume depending on the clearing price set by the marginal unit. The tolerances are set by BEIS based on the size of a typical CMU and to limit gaming opportunities. Any differences between the cleared capacity and the target capacity in the T-4 auction can be accounted for in the T-1 auction.

7.3.3 Comparison with T-4 for 2025/26 recommendation

In the 2021 ECR, we recommended a capacity to secure for 2025/26 of 44.1 GW which was 2.8 GW above the Base Case requirement of 41.3 GW. This recommendation assumed 7.0 GW of previously contracted capacity (net of 0.5 GW storage de-rating factor change). Our recommendation for the T-4 auction for 2026/27 is 0.2 GW lower than our recommendation for 2025/26 in the 2021 ECR. This is due to several increases totalling 2.2 GW that are offset by decreases totalling 2.4 GW.

The increases total 2.2 GW:

- An increase of 0.4 GW resulting from an increased differential of the LWR outcome to the Base Case – the 2.8 GW non-delivery sensitivity set the LWR requirement in the 2021 ECR and the 3.2 GW non-delivery sensitivity in the 2022 ECR. In the 2022 ECR, the recommended capacity to secure corresponds to a LOLE for the Base Case of 0.3 hours (see Section 7.3.5) whereas in the 2021 ECR, the recommended capacity to secure corresponded with a slightly higher LOLE for the Base Case of 0.5 hours.
- A 0.2 GW increase resulting from slightly lower non-CM renewable capacity and assumed opted-out or ineligible (below 1 MW) autogeneration (see Table 22 for breakdown).
- A 1.2 GW increase due to a higher peak demand for 2026/27 compared to the 2021 Base Case peak demand for 2025/26, reflecting a general increase in electrification across each of the sectors with the Future Energy Scenario modelling.
- An increase of 0.4 GW due to a change in estimated de-rated storage awarded multi-year contracts from 2020/21 onwards

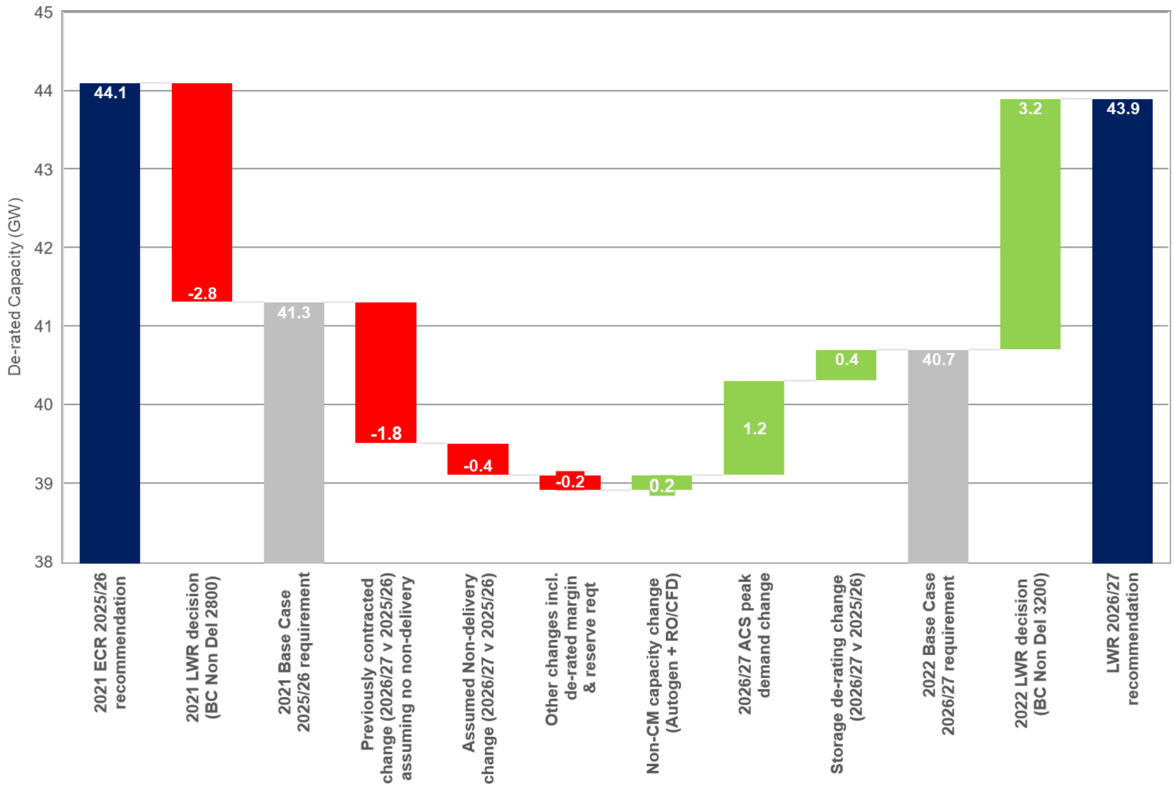
The decreases total 2.4 GW:

- A 1.8 GW net reduction due to an increase in previously contracted capacity arising largely from capacity awarded multi-year agreements in the 2025/26 T-4 auction.
- A 0.4 GW net reduction due to less additional non-delivery assumed in the 2022 Base Case (compared to the 2021 Base Case).
- A small net decrease (0.2 GW) due to other changes, (e.g. change in de-rated margin required for 3 hours LOLE compared to the 2021 Base Case, change in reserve for largest infeed loss and rounding).

This analysis includes the risk of further non-delivery (up to a maximum of 6.8 GW in the most extreme non-delivery sensitivity). However, we note that if this non-delivery risk were to reduce, e.g. due to a change in market conditions or CM rules, this could result in a lower demand curve target recommendation in the T-1 auction, which will be reassessed in the 2025 ECR. We note also that the T-1 target capacity is subject to a minimum of half the original set-aside which could limit the size of any reduction.

The following waterfall chart, Figure 38, shows how the original 44.1 GW requirement for the T-4 auction for 2025/26 (derived from the 2021 Base Case 2.8 GW non-delivery sensitivity) has changed into a recommended requirement of 43.9 GW (derived from the 2022 Base Case 3.2 GW non-delivery sensitivity) as a result of the 0.2 GW net decrease described above.

Figure 38: Comparison with recommended T-4 requirement for 2025/26 in 2021 ECR



Note: intermediate totals in grey above show requirements for 2021 Base Case and 2022 Base Case

Section 4.9 shows how the requirement for CM-eligible capacity changes over a 15-year horizon. This section shows a general increase for three of the scenarios modelled as a result of higher peak demands. For the other scenario, the requirement remains generally stable across most of the period, as increases in peak demand are offset by increases in non-CM capacity. For some scenarios, there is a decline in the last few years resulting from an increase in low carbon capacity assumed to be outside of the CM. All scenarios show an increase in 2027/28 when RO and CFD support for biomass conversion ends. During the later years of the period, significant amounts of RO-supported wind capacity will also come off support reducing the capacity outside of the CM and increasing the requirement for the CM-eligible capacity.

7.3.4 Robustness of LWR approach to sensitivities considered

During previous discussions around the potential for non-delivery (ND) and over-delivery (OD) sensitivities, a question was raised around how sensitive the LWR outcome was to the sensitivities included. e.g. maximum level of non-delivery; a sensitive outcome is one that would change every time the included sensitivities changed. To address this, we ran the LWR tool with some of the highest and lowest cases removed. In doing this, if the LWR tool selected the requirement from a FES scenario, the requirement for the nearest Base Case sensitivity requirement was selected (as per the methodology outlined in Section 2.6 of the 2016 ECR). The results from this are shown in Table 20.

Table 20: Sensitivity of LWR outcome to scenarios / sensitivities included in LWR

Sensitivities added or removed	2026/27 outcome
Standard range	43.9
Include additional 4.0 GW over-delivery sensitivity	43.9
Remove Leading the Way scenario	44.3
Remove 6.8 GW non-delivery sensitivity	43.5
Include additional 7.2 GW non-delivery sensitivity	44.3

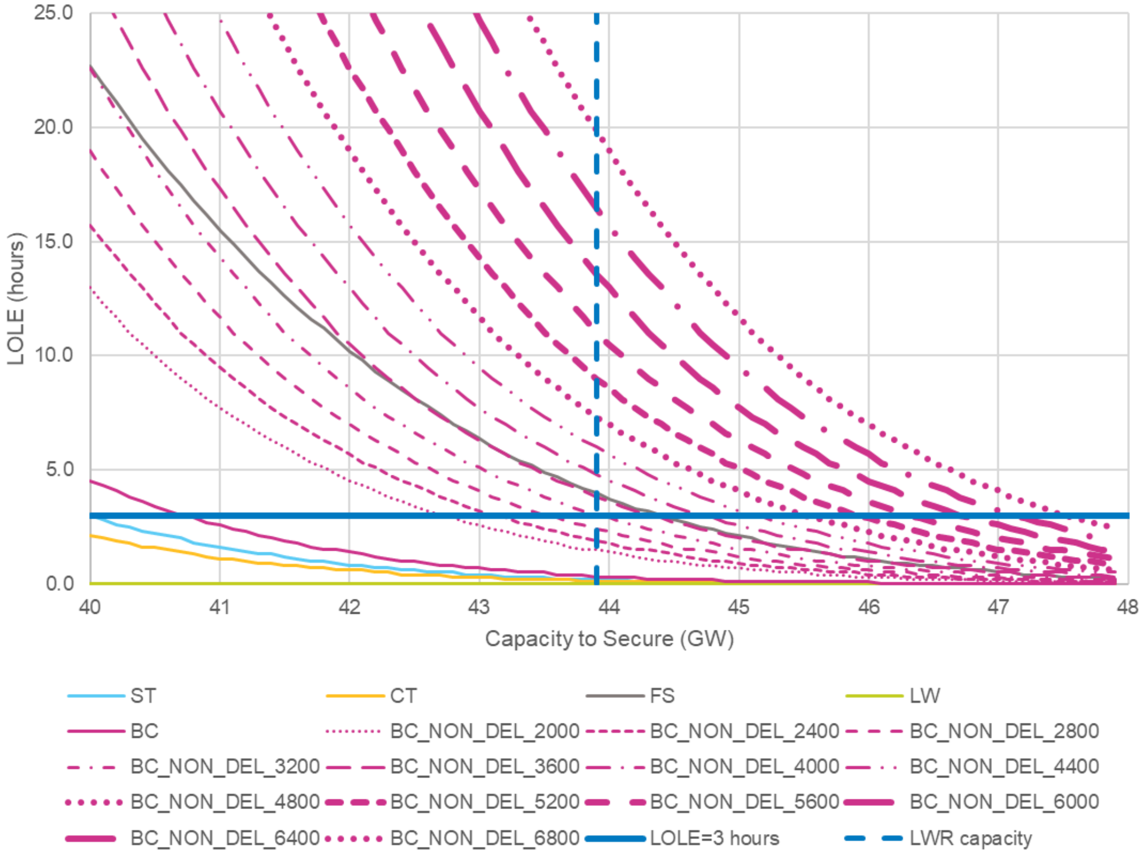
Removing the lowest target capacity case (Leading the Way) increases the LWR outcome by 0.4 GW. Adding a higher target capacity case (7.2 GW non-delivery) increases the LWR outcome by 0.4 GW. Removing the highest case currently in the LWR range (6.8 GW non-delivery) reduces the LWR outcome by 0.4 GW. No other single cases affect the LWR outcome. For example, adding additional over-delivery cases has no impact on the LWR outcome as the requirement of the LW scenario is below the requirements of the over-delivery cases.

We consider the outcome of the LWR calculation to be suitably robust and that the choice of scenarios and sensitivities included are well-justified as set out in Chapter 4.

7.3.5 Sensitivity of LOLE to T-4 Capacity to Secure

To help decision makers to understand the sensitivity of LOLE to the target capacity chosen for the T-4 auction, we have included Figure 39 which illustrates how the LOLE for the scenarios and highest non-delivery sensitivities varies with capacity to secure. We have not included all of the sensitivities on the chart to avoid overcrowding but the other sensitivities have LOLE values below the non-delivery sensitivities shown (the values for all scenarios and sensitivities are in the ECR Data Workbook). As can be seen, reducing the capacity to secure to 42.7 GW would mean that the LOLE for the non-delivery sensitivities shown would be 3 hours or above and increasing the capacity to secure to 44.4 GW would keep the LOLE to 3 hours or below for the FS scenario and non-delivery sensitivities with non-delivery values of 3.6 GW or below. The LOLE for the Base Case is 0.3 hours for the recommended capacity to secure (43.9 GW) – this would increase to 0.8 hours for a capacity to secure of 42.7 GW and reduce to 0.2 hours for a capacity to secure of 44.4 GW.

Figure 39: Sensitivity of LOLE to Capacity to Secure – 2026/27



A. Annex

A.1 Demand Methodology

The demand projections are developed using in-house analysis which has used stakeholder feedback to inform it. Annual demands can be considered with the following breakdown:

- Domestic
- Industrial
- Commercial
- Transport
- Other/Sundry

Domestic

The domestic demand is created by using a bottom up method. Each of the component parts of the sectors' demand is modelled individually. Where there is a history then this is used as the starting point for the modelling. If a component part is novel then research, projects' outcomes and proxy data are applied as appropriate. These components are listed below, and each is projected individually which, when aggregated, form domestic demand for each scenario.

- **Appliances, including lighting:** A regression trend method flexed by the application of primary assumptions and appliance number caps. We have assumed energy efficiency gains in all our scenarios but with varying degrees depending on the scenario.
- **Resistive heat and hot water:** A methodology has been applied where we use the thermal efficiency of the housing stock rather than just the insulation to inform our modelling. The scenarios have been revised based on recent information. In decarbonising scenarios, the average household thermal efficiency will be much improved on today's average. Current electrical heat demand comes from published statistics[72].
- **Heat pumps:** All scenarios are a patchwork of heating technologies due to regional variations and the expectation that no single technology will dominate low carbon heat. As well as heat pumps: hydrogen, biomass, natural gas are also considered in scenario design. Heat pumps are assumed to be one of the key heat decarbonisation technologies and this has been reflected in the scenarios for many years. In the residential sector, air source heat pumps (ASHP) and hybrid air source heat pumps are rolled out to different degrees. Ground Source Heat Pump (GSHP) installations are fewer due to high installation cost and payback periods. District heat is largely powered by larger heat pumps, which in addition have access to a top up source of heat (e.g. gas/hydrogen/biomass boiler, and/or thermal storage). In decarbonising worlds, heat pumps are also assumed to penetrate into industrial "warm" processes and commercial space heat. Thermal storage in all sectors is assumed to be installed to differing degrees in order to optimise the overall GB energy system, particularly peak demands during winter.

[72] https://www.gov.uk/government/statistics/energy-consumption-in-the-uk

- **Consumer Flexibility:** This year, similarly to last year, Ofgem's updated retail market review data has been used alongside research from recent studies, to forward project customer engagement rates. This percentage is applied to the underlying domestic demand and also plays a role in engagement in relation to transport demand.

Industrial

Economic data provided by 'Oxford Economics' in Q4 of each year is used to create economic cases for GB economic growth. Retail energy price forecasts are also used. A range of price scenarios was used to improve the illustration of future uncertainty.

The model examines 24 sub-sectors (Industrial and commercial) and their individual energy demands, giving a detailed view of GB demand, and uses an error correcting model to produce projections for each sub-sector individually. The model then has two further modules to investigate the economics of increasing energy efficiency (e.g. heat recovery) and new technologies such as onsite generation (e.g. CHP) or different heating solutions (e.g. biomass boilers).

These modules consider the economics of installing particular technologies from the capital costs, ongoing maintenance costs, fuel costs, and incentives. These are used along with macro-financial indicators such as gearing ratios and internal rate of return for each sub-sector to consider if the investment is economical and the likely uptake rates of any particular technology or initiative. This allows us to adjust the relative cost benefits to see what is required to encourage uptake of alternative heating solutions and understand the impact of prices on onsite generation.

Finally, calculations are added which consider the impact of energy efficiency policy within the different scenarios.

Commercial

The same approach as described in the paragraphs above (in the industrial section) has been adopted this year.

This year we have refined our new spatial heat model that outputs results for commercial heat with greater granularity on a regional level[73]. The new model is intended to enhance our understanding of the potential decarbonisation routes, their likelihood, and the impact of these on networks as well as on consumers.

Transport

- **Road transport:** The model used is based on economics and a Bass Diffusion approach to forecast uptake rates of different vehicles (i.e. natural gas and hydrogen as well as electric vehicles) that may replace the Internal Combustion Engine as transport is decarbonised. This is combined with statistics on journey length in order to assess the associated electrical demand. We continue to incorporate the concept of vehicle sharing, autonomous vehicles and vehicle to grid electricity supply.

[73] https://www.nationalgrideso.com/document/190471/download

- **Rail**: Projections are applied to the electric rail demand based on stakeholder feedback, to illustrate different levels of rail transport electrification.

Other/Sundry

These are the demand components which do not fall directly into the categories above. For example, these include losses which are a function of the total demand figure, interconnector flows, or micro-generation which is required in order to translate the FES total energy demand into a distribution or transmission demand definition.

Peak Demands

Once the assessment of underlying annual demand is created, a recent historical relationship of annual to peak demand is applied. This creates an underlying peak demand to which peak demand components that history cannot predict are added. For example, electric vehicle charging or heat pump demand at times of peak demands on the transmission system.

For each of the scenarios we also applied a consumer engagement factor which increases in our greener scenarios.

The overlays to peak demand are:

- **Electric vehicles:** Based on the projected numbers, the potential user groups are assessed, how and when they could be charging (constrained and unconstrained), and data from recently published trials are incorporated. Data from an innovation project (Development of GB Electric Vehicle Charging Trials)[74] has been used to inform our modelling on home, workplace and public charging. Smart charging behaviour is assumed to differing degrees in all scenarios.
- **Heat pumps:** The number of heat pumps and heat demand, data from manufacturers, and trial within day profiles combined with performance statistics and historical weather trends are used to determine the electrical heat demand at peak. Thermal storage is assumed in the low carbon scenarios as part of the smart energy system and acts to reduce peak heat demands.
- **Losses:** As with annual demand, this is a function of total peak demand.
- **Industrial & Commercial Demand Side Response:** Created using desktop research and assumptions of future efficiency improvements, consumer engagement and information technology improvements.
- **Domestic peak response:** As with annual demand this starts with the smart meter roll-out numbers, project outcome data and perceived customer engagement rates. This gives a percentage peak demand reduction. This percentage factor is then applied to the peak demand.

Calibration

Both annual and peak demands are calibrated. Annual demands are calibrated to weather corrected metered transmission data, BEIS information and the FES assessment of non-transmission generation. The peak demand considered for the Base Case is the Average Cold Spell (ACS) demand.

[74] http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/04/20190329-NG-EV-CHARGING-BEHAVIOUR-STUDY-FINAL-REPORT-V1-EXTERNAL.pdf

Results

The results of the described methods provided are defined and shown in the Annex (Section A.5.1). For a more detailed description of the methodology and FES scenarios please refer to the FES Report, the FES Modelling Methods document or the FES Data workbook[75]. Note that the demand is defined on unrestricted basis as Demand Side Response can participate in the auction.

Recent forecasting performance

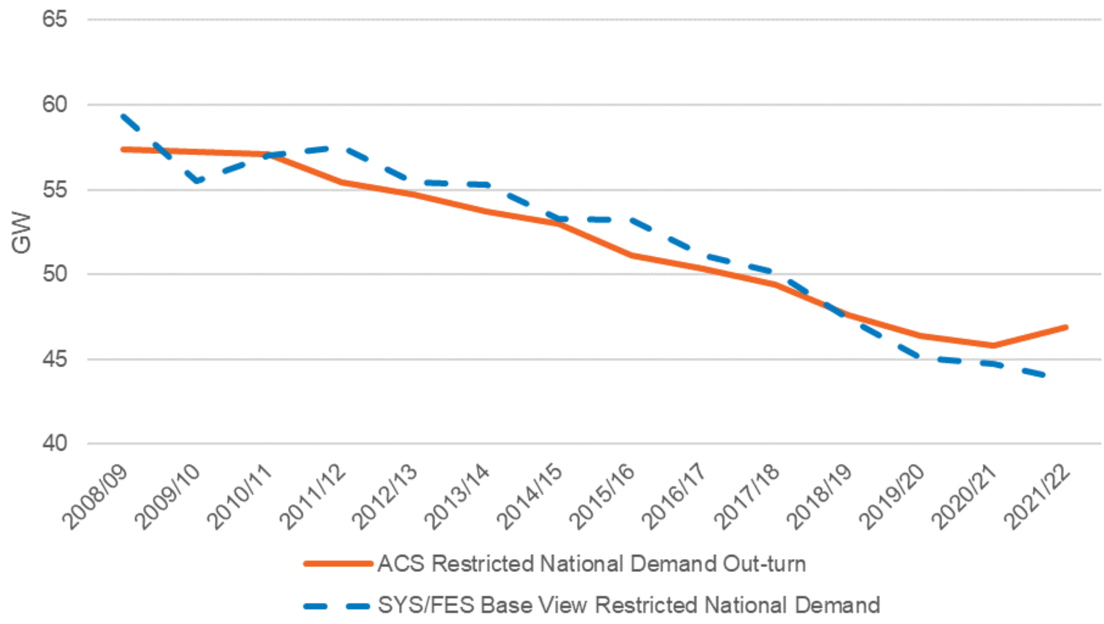
The PTE included data on National Grid ESO's demand forecasting performance in their 2019 report. Figure 40 provides an updated view of this data showing a comparison of National Grid ESO's winter ahead ACS restricted national demand forecast against outturn values.

The reasons for the higher than forecast actual ACS Peak National Demand appear to lie with the amount of embedded generation, but other elements are still being analysed. The hypothesis is that the following elements have a part to play, although the interaction between them is complex:

- The Covid-19 pandemic has made it difficult to assess consumer behaviour and demand usage compared to previous years – thereby making trend analysis irrelevant for recent years;
- Recent Grid Code modifications to remove the incentive for small embedded generators to run at time of peak has significantly reduced the observed Triad Avoidance, but the specific impact from these generators at time of peak under ACS conditions is unclear;
- The interaction between the 'demand turn-down' (related to avoiding Half-Hourly TNUoS charges) and Demand Side Response (related to high prices) needs to be reviewed;
- The actual output of the embedded generators (especially in the context of ACS conditions) needs to be reviewed to assess the appropriateness of existing assumptions of load factors compared to capacity ratings.

[75] https://www.nationalgrideso.com/future-energy/future-energy-scenarios

Figure 40: ACS Restricted National Demand Forecasting Accuracy



A.2 Generation Methodology

The power supply transmission backgrounds use a rule based deterministic approach. An individual assessment of each power station (at a unit level where appropriate) was completed, taking into account a wide spectrum of information, analysis and intelligence from various sources.

The scenario narratives provide the uncertainty envelope that determines the emphasis placed on the different types of generation technology within each scenario. Each power station was placed accordingly within their technology stack.

The placement of a power station was determined by a number of factors, such as market intelligence, energy policy and legislation. Project status and economics, which are applicable to that particular power station, are also taken into account. The contracted background or Transmission Entry Capacity (TEC) Register[76] provides the starting point for the analysis of power stations which require access to the National Electricity Transmission System (NETS). It provides a list of power stations which are using, or planning to make use of, the NETS. Although the contracted background provides the basis for the majority of the entries into the generation backgrounds, the analysis is not limited to generators with a signed connection agreement. Other projects where information has been received in the very early phases of scoping (i.e. pre-connection agreement) are also taken into account.

For power generation connecting to the distributed system (including capacity < 1 MW), alternative sources of data will be used as the starting point for assessment, such as the Embedded Capacity Register.

[76] https://www.nationalgrideso.com/connections/registers-reports-and-guidance

The generation backgrounds are then built up to meet the Reliability Standard in line with the FES Framework (i.e. all scenarios ensure security of supply is met).

A.2.1 Contracted Background

This contracted background provides a list of power stations which have an agreement to gain access rights to NETS; now and in the future. It provides valuable up to date information regarding any increase or decrease to a power station Transmission Entry Capacity which provides an indication of how a particular plant may operate in future years. This is then overlaid with market intelligence for that particular plant and/or generation technology type.

A.2.2 Market Intelligence

This section covers how market intelligence gathered through stakeholder engagement along with more general information is used to help determine which generation is likely to connect during the FES study period.

Developer Profile

This information relates to the developer of a certain project, or portfolio of projects, and provides an insight into how and when these projects may develop. Examples of information taken into account under this area are:

1. Is the developer a portfolio player who may have a number of potential projects at different stages of the process, in which case intelligence is gathered on the developers 'preferred' or 'priority' projects, or is it a merchant developer who is looking to become active within the electricity market?
2. How active is the developer in the GB electricity market?

Technology

This area looks specifically at future and developing technologies to gauge how much of a part certain emerging generation types may play in the generation backgrounds. Examples of information taken into account in this area are:

1. At what stage of development or deployment is the technology, e.g. has the technology been proven as a viable source of electricity generation?
2. Have there been trial/pilot projects carried out as with technologies such as wave and tidal?
3. Has there been a commercial scale roll-out of the technology following successful trial/pilot schemes?
4. Is there Government backing and support for the new technology?
5. Are there any industry papers or research regarding the roll-out of new technologies in terms of the potential scale of deployment should the technology be proven?

Financial Markets

Information relating to the financial markets is also a consideration in terms of how easy it will be for the developer to raise the capital to fully develop the project e.g. off the balance sheet or via the capital markets.

Consideration is also given to the economics for different types of generation, in terms of electricity wholesale prices, fuel prices and the impact of the carbon price (i.e. clean dark and spark spreads) which may impact the operational regime on a technology and/or plant-specific basis.

A.2.3 FES Plant Economics

This area is a key feed-in to the power generation backgrounds and explores economic viability and how a particular plant or group of plants could operate in the market now and in the future. The results of the analysis inform the transmission generation backgrounds, particularly plant closure profiles.

A.2.4 Project Status

The project status is especially important when determining at what point in time a new generator may become operational. For a new plant, factors such as whether a generator has a signed grid connection agreement, where in the consenting process the project is and if the developer of the project has taken a financial investment decision are all key in determining the timing of future projects. Depending on the project status, a likelihood rating is then given to the plant. For example, if the plant only has a grid connection agreement and no consents it will be ranked far lower than a power station that has these or is physically under construction. For existing power generation, it is important to consider any decommissioning dates (for example nuclear), potential replanting of stations (for example wind) and the lifecycle for the particular technology.

A.2.5 Government Policy and Legislation

It is important that the power supply scenarios reflect Government policy and initiatives for particular generation projects and / or technologies. This may be in the form of financial support for selected technologies that are targeted and developed, such as the low carbon technologies; nuclear, offshore wind, marine energy and CCS. Alternatively, it could be in the form of market-wide mechanisms such as the Capacity Market that aims to ensure that there is sufficient capacity on the system to meet the Reliability Standard.

Energy legislation enacted at the European and national level will impact which power supply sources are developed and connected to the NETS. For example, renewable energy targets are intended to reduce reliance on high carbon fossil fuels by promoting renewable sources, therefore making it very likely in FES scenarios with a high green ambition that the NETS will experience much more intermittent renewable capacity. Another example is the plant that may have to be modified to comply with environmental directives, such as the Industrial Emissions Directive (IED) and the Medium Combustion Plant Directive (MCPD). This legislation places restrictions on the number of running hours for fossil fuel power generation plants with regard to the harmful waste gases that they emit, unless investments are made to reduce this impact, and will affect decisions on whether to invest in new plants or maintain existing facilities.

A.2.6 Reliability Standard

The power generation backgrounds were developed for each of the scenarios based on the information gathered. The generation backgrounds are developed to both meet demand and to reflect the implementation of the GB Reliability Standard of 3 hours Loss of Load Expectation (LOLE) / year. In the early years of the FES study period, the generation backgrounds were driven by relatively more granular intelligence and therefore LOLE could potentially vary significantly year to year within this period. This can, for instance, be caused by plants without CM contracts staying open.

As a result, the LOLE calculation within the generation backgrounds has been slightly amended to ensure that it is consistent with the implementation of the CM Reliability standard and any short-term market perturbations around this metric. The modelling has also now moved from a pure transmission focus (i.e. assessing LOLE based on transmission-level generation against transmission-level demand) to a more whole-system approach whereby all generation (including units connected to the distribution networks) is assessed against total underlying demand. For further details on this, please refer to FES Modelling Methods document[77].

A.3 National Grid ESO Analysis Delivery Timeline 2022

The process and modelling analysis have been undertaken by National Grid ESO. We have also engaged with BEIS, Ofgem and the PTE throughout the process to ensure that our work can be appropriately scrutinised.

The work was carried out between September 2021 and May 2022 and builds on the analysis that was undertaken for the previous ECRs. The following timeline illustrates the key milestones over the different modelling phases of the work to the publication of the ECR:

- Development plan produced in September 2021
- Development projects phase October 2021 to February 2022
- Production plan developed in February 2022
- ECR modelling March to May 2022
- National Grid ESO's ECR sent to BEIS before 1 June 2022
- Publication of ECR in line with BEIS publishing auction parameters in July 2022

[77] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2020-documents

A.4 EMR/Capacity Assessment Development Projects Matrix

Table 21 lists all the proposed development projects and their respective ranking scores. Projects without a score were in progress or completed prior to the ranking exercise. Note that shaded projects either did not rank high enough or were deprioritised and therefore were not progressed.

Table 21: Development Projects Matrix

Ref.	Development Project Description	Rank*
EMR100	Review of the process by which modelled ranges for interconnected countries are used to inform a single auction de-rating factor	1
PTE58	A more comprehensive feed-forward analysis of how all of the main drivers of demand will evolve from the existing situation to influence the T-1 and T-4 base case peak demands should be developed to enhance the insights from the FES scenarios.	2
PTE60	The Root Sum of Squares or Simple Summation approach to multiple non-delivery risks needs to be fundamentally reconsidered in terms of the independence of the risks involved, or their dependence on common mode drivers, and their possible market responses induced. We suggest a more flexible rationale be developed based upon the characteristics of the different non-delivery risks.	2
PTE61	An empirical analysis of all past non-deliveries (and non-availabilities), as well as evident market responses, should be undertaken to look for any possible drivers of dependence between technologies, relevant CM auction clearing prices and average energy market prices.	2
PTE59	The previous Recommendation 52 regarding the factors affecting the evolution of peak demand and potential stress period behaviour should be re-visited soon given the importance of the drivers on the shape of peak demand and its impact on the capacities to secure, particularly the T-4 value.	5
EMR84	Explore use and implementation of credible, extreme weather events based on scenarios developed by National Infrastructure Commission / Met Office (data sets expected in May 2021 and will be publicly available at: https://nic.org.uk/studies-reports/national-infrastructure-assessment/characterising-adverse-weather-uk-electricity-system/)	6
EMR80	Review of assumptions and method that leads to the construction of the conventional distribution used in the LOLE calculation.	7
PTE53 Phase 2	Further consideration of whether de-rating factors for embedded generation could be derived from alternative data sources (this is a follow-up to project PTE53 carried out in 2020/21)	8
PTE63	A more thorough analysis of the duration limits for turn-down DSR	8
PTE64	The consistency of the implicit derating of interconnectors for the DDM procurement analysis and the determination of individual country derating factors should be made more transparent.	8
EMR94	Creation of queries to extract data from a new FES database to be set up (on a new Data Analytics Platform) - may be deferred to 2022/23 as Data Analytics Platform is not yet built	11
EMR96	Interconnection de-rating factor modelling improvements	12
PTE57	A fundamental analysis of the sequential nature of the capacity procurement, taking account of the appropriate caution needed in relation to the quantifiable and unquantifiable uncertainties, risks and their consequent recourse costs	12
CMR7	Reliability Standard analysis to feed in to the 10 year review	14
EMR95	Review method for calculating historical outturn margins	14
EMR82	Examine the advantages and risks of using historical data when determining interconnector de-rating factors. Provide and evaluate options on potential roles for historical evidence, alongside future-focused probabilistic modelling.	16
EMR93	Streamlining and automation of 'FES to DDM' translation tools (migration from SAS/Excel to Python/Excel/csv)	16
PTE56	The Technical Reliability of HVDC links should be considered more fully and whether the technical reliability of interconnectors and perhaps private links to large offshore wind farms, should become more explicitly part of the procurement methodology in future (this falls within the remit of BEIS rather than National Grid ESO).	16

Ref.	Development Project Description	Rank*
EMR87	Review assumptions on reserve for largest loss in light of changes to reserve products (e.g. dynamic containment) and the recommendations in the Frequency Risk and Control Report (FRCR).	19
EMR85	Update DDM version to further automate data inputs and simplify outputs.	20
EMR86	Work with LCP to explore the potential for capturing more of the modelling uncertainties via stochastic modelling in the DDM.	21
EMR97	Assess emerging risks to security of supply	22
EMR99	Investigate the impact of wind constraints at peak in net zero scenarios	22
EMR101	Assess availability of conventional generation at times of high demand-net-of-wind	24
EMR74	Carry out in depth review of ECR content with BEIS, Ofgem and PTE.	25
PTE62	BEIS and Ofgem should consider the timing of all CM related activities each year in order to allow pre-qualification and auction results to better inform National Grid ESO's modelling and give parties longer to deliver new build plant after the T-4 auction.	25
EMR81	Investigate the feasibility of whether we can use BID3 for capacity assessment modelling that could allow us to retire our internal capacity assessment model used for Winter Outlook	27
EMR59	Improve historical demand time series for LOLE modelling (using Electralink data)	28
PTE65	Further analysis of the availability of DSR and Embedded Resources in Europe at the times of GB stress	29
EMR67	Review treatment of non-CM capacity in the DDM to better account for capacity in later years (after CM target years) that comes to the end of its CFD / RO contracts	30
EMR44	Estimate the range of potential impact of non-delivery and over-delivery of non-CM (e.g. renewable) capacity in the Base Case.	31
EMR98	Consider moving the start of the modelling for the ECR forward by up to a week	32
EMR45	Develop a proper demand time series shape for FES future security of supply modelling - at the moment we are using 2005-2017 demand time series shapes, but these are likely to be inadequate for > FES 2030 margins assessment work.	33
EMR60	Review wind power curves and consider creating large offshore power curve if additional data is available for large offshore wind turbines and there is a significant difference to the existing offshore power curve. Test impact of new power curves on model outputs.	34
CMR6	Consider duration-limits (if any) in the DSR and diesel generation technology types.	35
EMR68 / CMR4	Develop methodologies for calculating de-rating factors for new technologies that may enter the CM auctions	35
EMR78	Update and automate the import of data in the Least Worst Regret Tool	35
EMR61	If the introduction of a large offshore wind power curve is justified (see EMR60), update models (CA model, DDM, UEM) to incorporate this new class.	38
EMR88	Consider automating data checking elements of DDM QA process	39
EMR48	Develop a "net demand" version of the CA and DDM models, to avoid the use of an exogenous scalar applied to wind in the time collapsed calculations	40
PTE51 Phase 2	Different hybrid site / constraint combinations and using the outputs of these studies to propose a de-rating methodology for constrained hybrid sites	40
PTE50	Investigate the economic drivers of the DSR sector and distributional impacts of Ofgem's proposed changes to the charging regime.	42
PTE49	Build upon previous economic modelling of the viability of embedded generators to provide a more comprehensive view on potential embedded non-delivery.	43
EMR79	Develop an updated storage EFC proxy for the Capacity Assessment Model	
EMR83	2021 CA modelling improvements and update UEM demand & wind stream files	
EMR89	Streamlining manual processes in the Capacity Assessment Model	
EMR92	CM Register database migration from SAS/Excel to Python/Excel/csv files	

*represents total scores based on scorings provided by National Grid ESO, BEIS and Ofgem.

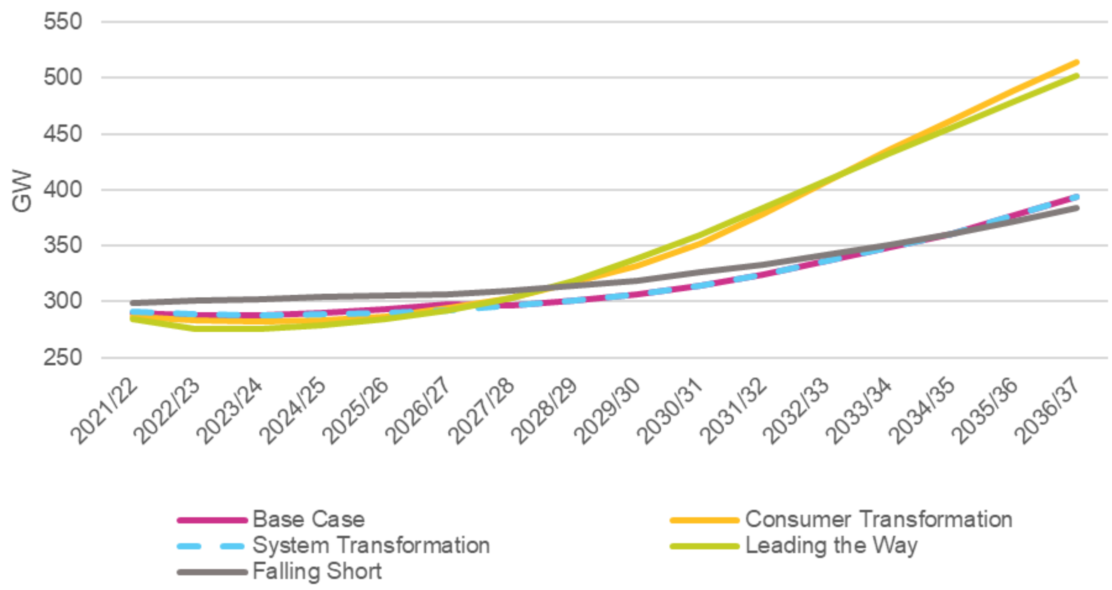
A.5 Detailed Modelling Assumptions

The following sections describe in more detail the modelling assumptions outlined in the main report. National Grid ESO provides the details of the key inputs for the DDM model. Other assumptions (e.g. technology costs) were provided by BEIS.

A.5.1 Demand (annual and peak)

Figure 41 shows the annual demand used for Base Case and the four FES scenarios covering the next 15 years. All sensitivities use the same annual and peak demand as the Base Case (except for the high and low demand).

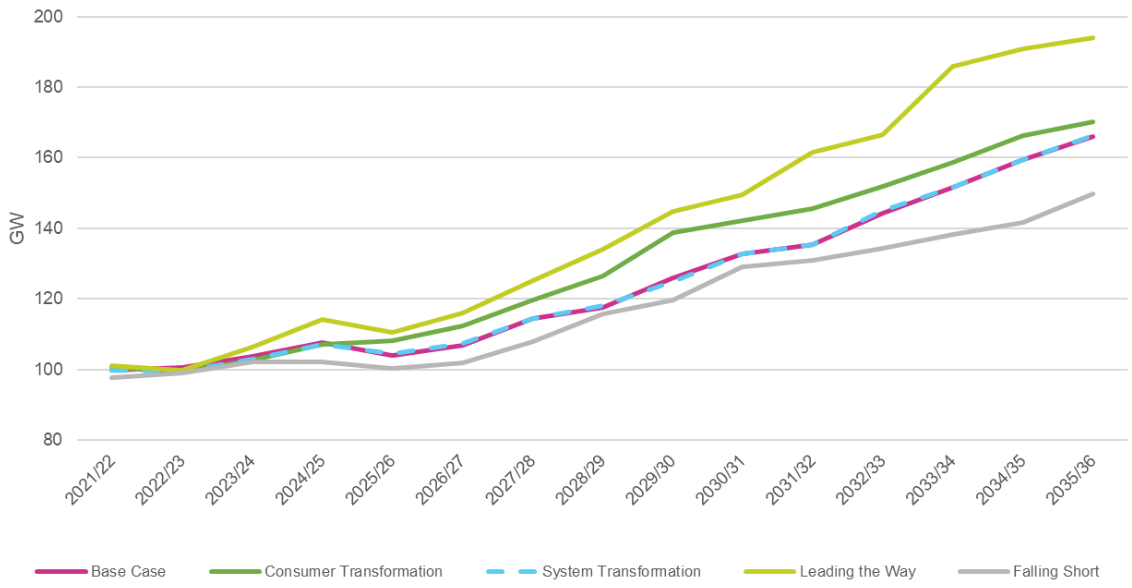
Figure 41: Annual demand by scenario



A.5.2 Generation Capacity Mix

Figure 42 shows the generation mix (nameplate capacity at winter peak, excluding solar PV) for the four FES scenarios and Base Case from the DDM model. The ECR Data Workbook shows the split between CM and non-CM capacity. The Non-CM capacity shows increases in most years after 2022/23 but falls in some years where large amounts of wind come off RO support and increases more slowly in 2027/28 due to the end of RO and CFD support for biomass conversion.

Figure 42: Generation peak capacity by scenario



A.5.3 CM-ineligible Capacity

Table 22 gives a breakdown of de-rated CM ineligible capacity (excluding previously contracted capacity) for the Base Case in 2023/24 and 2026/27. The autogeneration in 2023/24 includes 0.4 GW assumed over-delivery (see 5.2). Please note that the capacities by technology may not sum to the total ineligible capacity due to rounding.

Table 22: Breakdown of De-rated CM ineligible capacity (GW) for 2023/24 and 2026/27

Generation type	2023/24 Capacity (GW)	2026/27 Capacity (GW)
Onshore Wind	2.7	3.0
Offshore Wind	2.6	3.6
Biomass	3.9	4.0
Autogeneration	0.7	0.3
Hydro	1.1	1.1
Landfill	0.4	0.4
Other	1.3	1.8
Total	12.7	14.1

A.5.4 Station Availabilities

As with the previous three years, small-scale/embedded CM-eligible technologies are mapped to the closest equivalent transmission-connected technology class, as required by the CM rules. For some non-CM technologies (for which availability values are modelling assumptions not prescribed by CM rules), we have amended the de-rating factors based on the best range of data sources available to us, with results summarised in Figure 43. Interconnection EFC values are calculated using the method described in Section 3.3.2 of this report. The EFCs for storage, wind and solar for the DDM runs are slightly different to the auction de-rating factors described in Section 5 as per Section 2.5.2 of the 2019 ECR[78]:

- Storage de-rating values in the DDM are identical to the de-rating factors in Figure 20 and Figure 21, with the exception of T-4 values for durations above 6 hours which match the pumped storage availability of 95% so that the total DDM storage de-rated capacity (GW) broadly matches the Unserved Energy Model (UEM) storage fleet EFC (GW).
- Wind EFC %s (shown in Figure 44) are calculated by the DDM using a scaling factor of 0.75 that reduces wind generation on high demand days. This value was set in 2019 so that the DDM wind EFC broadly matched the UEM wind fleet EFC (GW).
- Solar EFC %s (shown in Figure 44) are calculated so that the sum of the individual fleet EFCs (wind EFC + storage EFC + solar EFC) in the UEM broadly matched the combined unconventional (wind+storage+solar) fleet EFC.

Figure 43: Non-CM technology availabilities

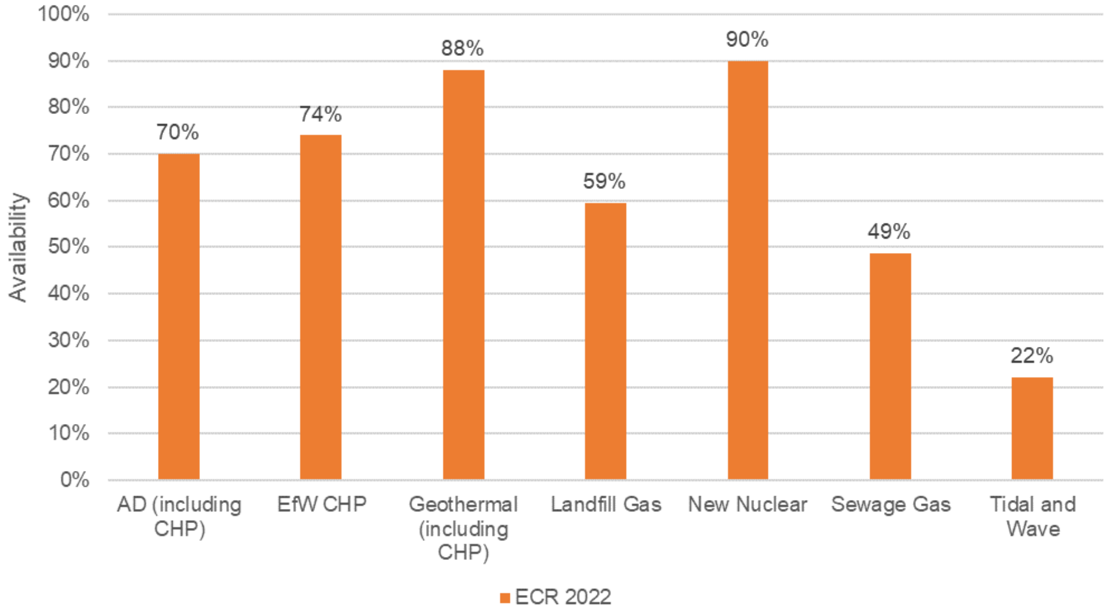
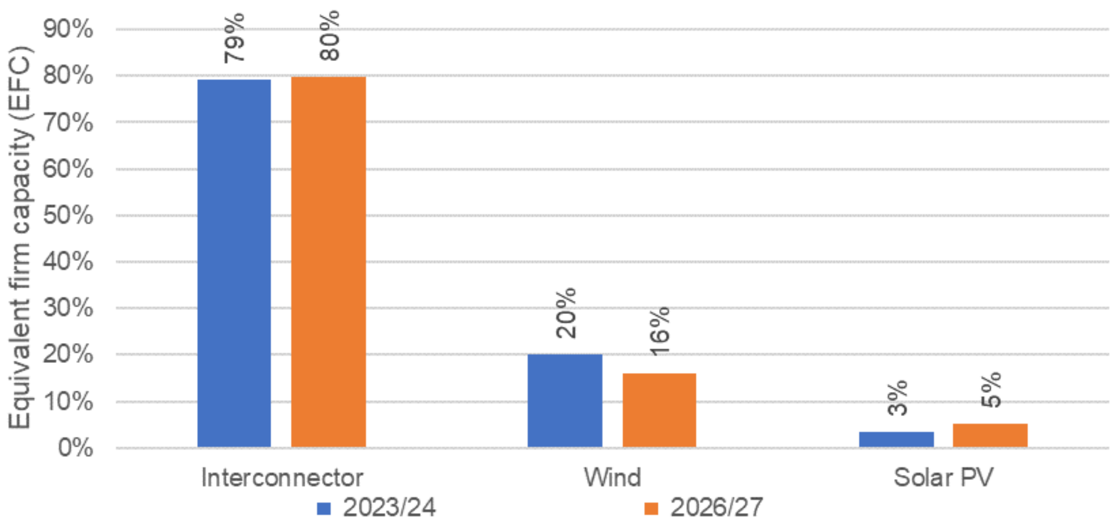


Figure 44: Interconnector, wind and solar fleet EFCs

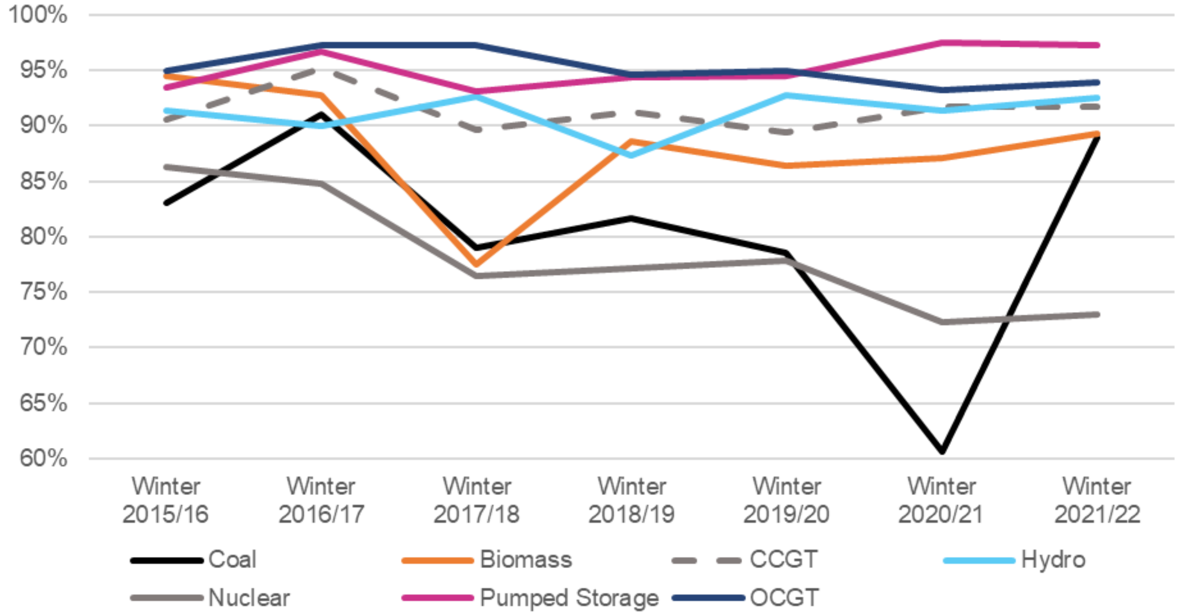


[78] See page 23 of https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/Electricity%20Capacity%20Report%202019.pdf

A.5.4.1 Conventional Transmission Station Availabilities

Figure 45 shows the station availabilities from each of the previous 7 winters for transmission-based generation.

Figure 45: Station availabilities

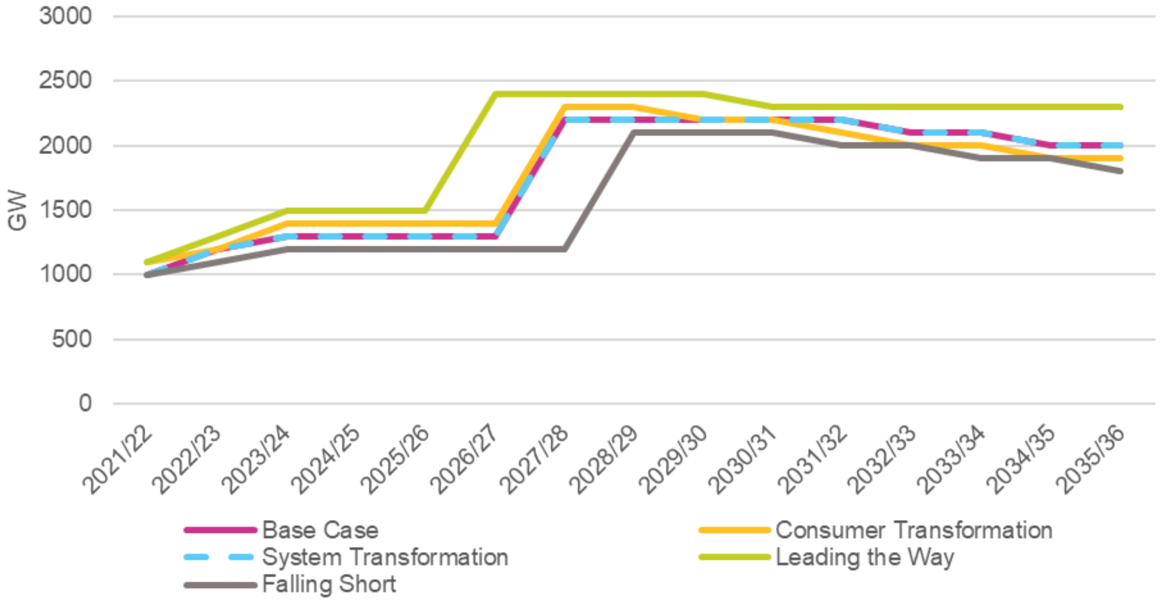


A.5.5 Reserve for Response (to cover largest infeed loss)

National Grid ESO has to hold capacity in reserve in order to maintain system operability if a loss of generating capacity occurs. This capacity has to be accounted for in the LOLE calculation and is added to the peak demand assumptions. The reserve for response depends on a number of factors. This includes the largest loss on the system and the forecast demand[79]. Figure 46 shows the reserve requirement to cover the largest in-feed loss[80] for each scenario. Note that the largest infeed loss increases as new capacity connects to the network, requiring a higher level to be held. Any other reserve held in addition to this (e.g. day ahead contingency) is assumed to be generating at real time if a stress event occurs; the only capacity assumed to be held back in reserve during a stress event is the reserve for largest loss.

[79] See Annex 2 of https://www.elexon.co.uk/wp-content/uploads/2014/12/234_08a_Attachment_A_P305_Detailed-Assessment-v1.0.pdf
[80] Note: the reserve for largest infeed loss above is not included in the peak demand values shown earlier

Figure 46: Reserve to cover largest infeed loss by scenario



A.5.6 Conventional Plant Types

Table 23 describes the plant types included in each technology class.

Table 23: Conventional Plant Technology Classes

Technology Class	Plant Types Included
Oil-fired steam generators	Conventional steam generators using fuel oil
Open Cycle Gas Turbine (OCGT)	Gas turbines running in open cycle fired mode
Reciprocating engines (non-autogen)	Reciprocating engines not used for autogeneration
Nuclear	Nuclear plants generating electricity
Hydro (excl. tidal / waves and pumped storage)	Generating Units driven by water, other than such units: a) driven by tidal flows, waves, ocean currents or geothermal sources; or b) which form part of a Storage Facility
CCGT	Combined Cycle Gas Turbine plants
CHP and autogen	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas
Coal	Conventional steam generators using coal
Biomass	Conventional steam generators using biomass
Energy from Waste	Generation of energy from waste, including generation of energy from: a) conventional steam generators using waste; b) anaerobic digestion; c) pyrolysis; and d) gasification.
DSR[81]	

[81]Details of the DSR De-rating Methodology can be found on the EMR delivery body website https://www.emrdeliverybody.com/Capacity%20Markets%20Document%20Library/DSR%20De-rating%20Information.pdf

A.6 Detailed Modelling Approach

A description of the detailed modelling approach was included in page 81 of ECR 2017[82].

In addition to that information, we have also included further information on the assumptions that form the non-delivery and over-delivery sensitivities. We have also included information here on the sensitivities that were considered but not included in this year's analysis.

A.6.1 Assumptions for the over-delivery and non-delivery sensitivities

Table 5 and Table 6 summarise the components for the non-delivery and over-delivery sensitivities. These tables show the different types that we considered, the amount of each and the combination that results in the maximum value for each year. Table 24 and Table 25 provide further commentary on these values.

Table 24: Assumptions for non-delivery sensitivities

Non-delivery type	2023/24 T-1	2026/27 T-4	Comments
Large thermal	3.0	3.8	There is significant uncertainty on large thermal assets (coal and gas) due to challenging economic conditions and the drive to net zero. The higher T-4 number reflects greater uncertainty and risk on this time horizon.
Nuclear	1.8	0.9	We have experienced recent winters with two stations on extended outages (2018/19 to 2020/21). The lower T-4 number reflects expected closures of the nuclear fleet.
Small embedded	0.7	0.7	We assume 0.7 GW based on changes to embedded benefits and environmental legislation that could potentially change the business case for small-scale generation. This could also cover some risk of delays to new projects.
Unproven DSR	0.4	0.3	Reflects risks from previous observations that up to around 25% unproven DSR has failed metering tests in the past
Interconnectors	1.5	2.7	Non-delivery based on combination of assuming interconnectors deliver in line with lower end of de-rating factor range based on our modelling (represents 0.8 GW for T-1 from 2019 ECR for 2023/24 and 2 GW for T-4 from 2021 ECR using 2025/26) and interconnector reliability (assumed 0.7 GW based on a single cable outage).
Sum of non-delivery	7.4	8.5	
Market response	-1.2	-1.7	Potentially 1 GW from thermal plant staying open so this effectively offsets some of the non-delivery for large thermal. Potentially some response from interconnectors assuming 1/3 of the difference between auction de-rating factors and the top end of our previous modelled ranges.
TOTAL	6.0 rounded	6.8	Net total of around 6 GW is broadly consistent with the highest levels of past non-delivery observed in PTE 61 post T-1 auction.

* All values rounded to nearest 0.1.

[82] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf

Table 25: Assumptions for over-delivery sensitivities

Over-delivery type	2023/24 T-1	2026/27 T-4	Comments
Large thermal	1.0	1.0	Based on estimates that a large thermal plant many stay open without a CM agreement.
Nuclear	0	0	We assume nuclear stations will have a CM agreement if they are available.
Small embedded	1.5	1.5	Estimate based on comparing assumptions in our 2020 Base Case with capacity contracted in the CM for delivery years 2017/18 to 2020/21. Potentially as much as 1.5 GW staying open but not contracted, although highly uncertain. It could also include early delivery of new build projects.
Unproven DSR	0.3	0.3	Based on estimates of DSR without agreements from 2018/19
Interconnectors	0.6	2	Assumes over-delivery in line with high end of de-rating factor ranges with 5% reduction to reflect technical reliability (represents 0.6 GW for T-1 from 2019 ECR for 2023/24 and 2 GW for T-4 from 2021 ECR using 2025/26)
Sum of over-delivery	3.4	4.8	
Market response	-0.7	-1.2	Assume 0.5 GW large thermal (e.g. CCGT) could close early in response to over-delivery from other sources plus lower imports from interconnectors, which may not be needed as much (assumes 1/3 of the differences between auction de-rating factors and lower end of previous modelled range)
TOTAL	2.8 rounded	3.6	

* All values rounded to nearest 0.1.

As described in Section 3.4.2, we estimated historical non-delivery in the CM over the winter peak period (December to February, when demand is at its highest) as part of development project PTE61. This was carried out using data from CM registers, REMIT outage information and other sources in October 2021. It considered different types of winter non-delivery and when it became apparent to us, such that we could reflect it in our ECR recommendations or in the final T-1 auction target (determined following the demand curve adjustment after prequalification and after which no further action can be taken). The timing of when non-delivery becomes apparent is uncertain as it depends on factors such as when terminations take place, when CM registers are updated, winter outages are known, and when assumptions on the ECR Base Case are finalised which means that data on when the non-delivery became apparent may be less accurate than the total non-delivery figure.

Table 26 shows the estimated de-rated non-delivery total by delivery year and includes:

- Capacity Market Units (CMUs) with terminated CM agreements covering the year
- CMUs with non-terminated multi-year CM agreements that were subsequently reduced to 1 year (resulting in non-delivery for years after the initial year)
- New CMUs with non-terminated CM agreements that had not met their minimum completion requirement by the winter of the delivery year
- Unproven DSR CMUs with non-terminated CM agreements that had not completed metering assessments by the winter of delivery year
- CMUs with non-terminated CM agreements with outages over whole winter of the delivery year that had not secondary traded their obligations by the start of winter
- for 2021/22: winter outages over the whole winter that were known in October 2021

Table 26: Estimated total historic winter non-delivery for recent years (from project PTE61)

Delivery Year	Total since agreements were awarded (GW)	Total Post T-4 ECR Recommendation (GW)	Total Post T-1 ECR Recommendation (GW)	Total Post T-1 Auction Target (GW)
2017/18	N/A*	N/A*	0.1	0.1
2018/19	5.4	5.4	3.7	3.7
2019/20	6.0	6.0	1.1	1.1
2020/21	11.4	8.3	6.5	6.5
2021/22	8.9	6.9	6.7	0.9^
Average	**7.9**	**6.7**	**3.6**	**2.5**

*Delivery year 2017/18 did not have a T-4 auction. It only had a T-1 auction (known as the Early Auction) and has therefore been excluded from the average in the first two columns

^ The demand curve adjustment after prequalification that informed the target for the 2021/22 T-1 auction accounted for around 5.8 GW of non-delivery after the ECR T-1 recommendation that was either known by then or was considered to be at significant risk of occurring

A.6.2 Sensitivities not included in this year's analysis

Dependence of Generating Units – The DDM implicitly assumes independence in availability of generating units. Several commentators/consultancies have suggested that this assumption is optimistic. For example, a fault in one unit can affect the other units on site or a station transformer fault could affect more than one unit or the operation of a station within a portfolio could be affected by the other stations in that portfolio. However, the data available associated with these issues is either very limited or difficult to interpret and translate for use into the future, making it very difficult to quantify for modelling purposes. Hence this sensitivity was not included in our modelling.

Renewable Plant Non-Delivery – This sensitivity was to reflect delays in delivering non-delivery from capacity not eligible for the Capacity Market (e.g. delays in building new capacity). However, as the Base Case and four scenarios in FES already reflect this uncertainty, it was not included in our modelling.

Black Swan Events – These are defined as events that 'deviate beyond what is normally expected of a situation and are extremely difficult to predict, being typically random and unexpected'[83], and which we consider to have very low probability but high potential impact. We have investigated nuclear type faults before and concluded that they were low probability and historically had been rectified ahead of the following winter (albeit with stations operating at a reduced capacity but this would be covered in the scenarios). However, for winters 2018/19, 2019/20 and 2020/21 two nuclear plants failed to return to full service so maybe this is not as certain as previously thought as the nuclear fleet nears the end of their operating lives. We have also considered extreme cold weather (e.g. January 1986/87) combined with low wind, but this would involve changing more than one element which violates the principles behind the sensitivities of only including credible outcome by changing one variable. Extreme weather events may be most likely to impact first the transmission and distribution systems; insofar as 'black swan' events impact generation, the first recourse would be to 'latent capacity' on the. Given this and the economic or policy events relating to uncertainty around coal will be addressed through the non-delivery sensitivities, we agreed with BEIS and the PTE not to include any 'black swan' event sensitivities.

[83] https://www.investopedia.com/terms/b/blackswan.asp

CMU misalignment to TEC – This sensitivity relates to the CMUs (Capacity Market Units) connection capacity being greater than TEC (Transmission Entry Capacity) values for some transmission connected stations so that when the de-rating factors are applied, they result in nearly 100% availabilities for many stations. This clearly puts security of supply at risk, as no plant is 100% available so the auction has under secured capacity. However, our modelling mitigates this risk by only using capacities based on TEC, so all our recommendations take account of this anomaly as best it can, with only the T-1 auction potentially under securing if the stations successful in that auction have CMUs greater than TECs. Hence, we have agreed not to include this sensitivity.

Combined Sensitivities – Several system operators around the world consider combined sensitivities within their process for calculating the required capacity to meet their respective reliability standards. Consequently, we investigated whether this was appropriate for the GB process, particularly in relation to the use of a potential hybrid approach (see the 2017 ECR). First of all, we considered the potential use of combined sensitivities within the LWR tool. We concluded that this would, if included, result in lower probability sensitivities such as combined sensitivities being given equal weightings as sensitivities with only one variable changed which would be inappropriate. Secondly, we considered it as part of the hybrid approach but to change the answer materially required such a low probability sensitivity that it may be considered more like a 'black swan' event and it was thus decided not to include it.

This was revisited again as a development project in response to recommendation 46 of the 2019 PTE report. This led to similar conclusions as those drawn in the work reported in the 2017 ECR supporting the decision not to include these events as sensitivities.

Interruption to GB gas supplies – A potential interruption to GB gas supplies could impact the availability of gas generation. However, as the likelihood of such an event is low, it has not been included in our modelling for the same reasons that we have not included other low probability or black swan events.

Adverse weather events – Our weather history is relatively short (< 17 years) and so won't include potential weather events that could occur in future. These may become more adverse due to climate change and will likely become increasingly important as the generation mix is increasingly dependent on wind / solar. At the moment, we don't have a credible data set. We have been supporting a project led by the National Infrastructure Commission and Met Office to develop credible adverse weather data sets that can be used by energy modellers. This will include weather scenarios that could have occurred but haven't.

Non-delivery risks relating to environmental legislation and carbon pricing – It is possible that changes to environmental legislation and carbon pricing could impact the running hours and profitability of thermal stations and subsequently increase the risk of non-delivery. While we model non-delivery risk, we have not explicitly modelled risks due to environmental legislation or carbon pricing. The scenarios in the FES consider different generation mixes that would cover some of this uncertainty (e.g. different diesel closure profiles). In addition, since the modelling is targeting 3 hours LOLE, we are only interested in a very small portion of the year, which may not be significantly impacted by running hour restrictions. Should we identify specific risks relating to non-delivery due to either of these factors, then we could consider including within the existing non-delivery sensitivities.

A.7 Storage De-rating Factor Data Assumptions

As reported in Sections 3.3.3 and 5.1, we have calculated the de-rating factors for duration limited storage in the 2022 ECR based on an updated view of storage durations and capacities (as per Figure 47 and Figure 48 below).

Please note that given that this work was carried out before the Base Case storage capacity figures were finalised, the capacities in the table may differ slightly from the final published values. In 2017, we ran an industry consultation[84] on the methodology and modelling assumptions for the new approach to de-rating the sub-categories of this technology type. The final de-rating factor number for each duration limited storage class sub-category is (amongst other modelling assumptions) influenced by each of the following methodology attributes:

- (EFC) The incremental Equivalent Firm Capacity of a perfectly reliable storage unit (of each respective duration) and of a relatively small capacity added to the margin of a Base Case targeted at 3 hours LOLE, the GB Reliability Standard. The Base Case is set up to reflect the expected composition of the GB power system in each T-1 and T-4 target year in question. One key issue is that, as indicated by our report to industry in 2017, the assumption of the amount and composition of storage in the Base Case in each target year will influence the EFC of incremental storage units added thereafter – more short duration storage in the Base Case will tend to reduce the incremental EFC of storage units added thereafter. The assumptions in the 2022 ECR Base Case for the penetration of storage by capacity and duration are listed in the figures below.
- (TA-PS) The technical breakdown parameter to be applied to the storage technology class overall, namely that which is calculated as the historical technical availability of pumped storage over the last 7 years' winter periods - calculated as 95.25% this year.
- The histogram of stress event durations of the same Base Case (see Figure 49 and Figure 50), whereby all durations at or above that duration threshold which corresponds to longer than 95% of potential stress events shall receive a de-rating factor equal to the historical technical availability of pumped storage (TA-PS), and those that are shorter than this duration will receive a de-rating factor equivalent to the product of the incremental EFC and the technical availability of the storage class overall i.e. namely (EFC)*(TA-PS).

[84] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf

Figure 47: Base Case duration limited storage T-1 assumptions (near final)

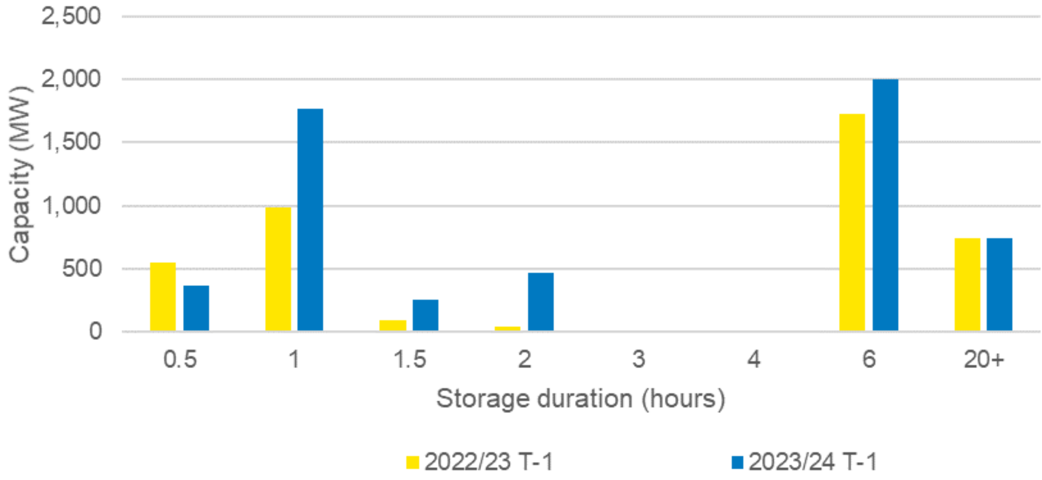
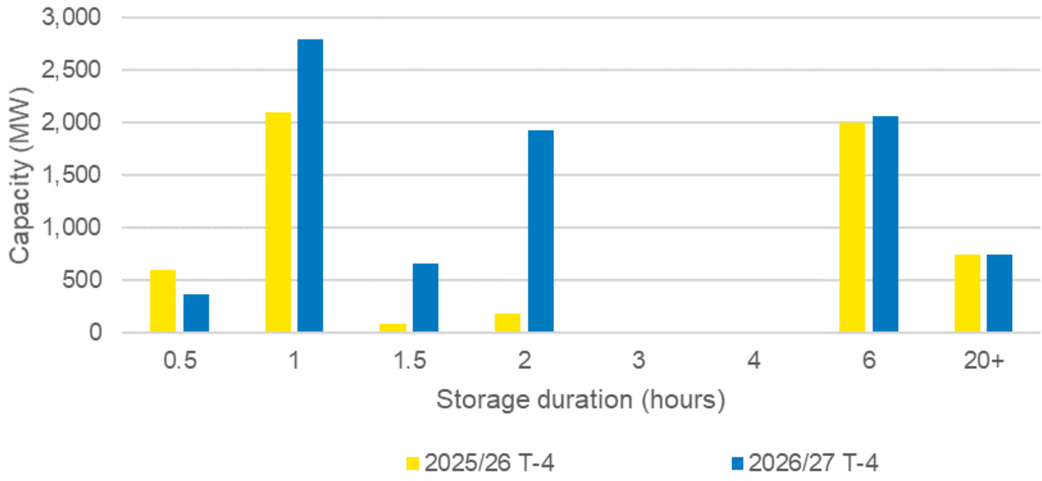


Figure 48: Base Case duration limited storage T-4 assumptions (near final)



For both the T-1 year and particularly the T-4 year, there is a significant overall increase in the amount of shorter duration storage capacity in the 2022 ECR Base Case compared to the 2021 ECR Base Case. In particular, there is an increase in capacity for 1-2 hour duration systems offset slightly by a small decrease in 0.5 hour duration capacity. This change reflects updated market information. For example, storage units have been awarded capacity market agreements in recent auctions.

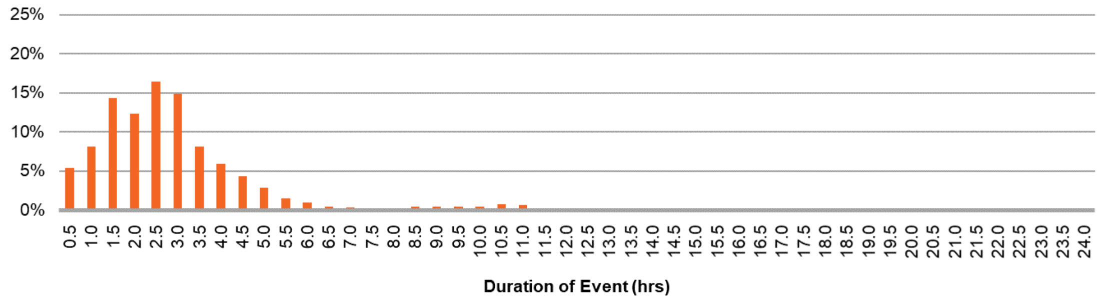
Our renewables de-rating consultation[85] showed (slide 22) that solar capacity also has an impact on storage incremental EFCs, with large increases in solar capacity resulting in modest increases in storage EFCs. However, this impact is small compared to the impact of increases in short-duration storage capacity that reduces the storage incremental EFCs.

Due to the higher storage capacity, the incremental EFCs have decreased since the 2021 ECR for the T-1 and T-4 years. In addition, the duration threshold corresponding to 95% of stress events has increased from 4.5 hours to 6 hours in the T-1 year. Similarly, the duration threshold corresponding to 95% of stress events has increased from 5.5 hours to 9.5 hours

[85] https://www.emrdeliverybody.com/Prequalification/EMR%20DB%20Consultation%20-%20De-Rating%20Factor%20Methodology%20for%20Renewables%20Participation%20in%20the%20CM.pdf

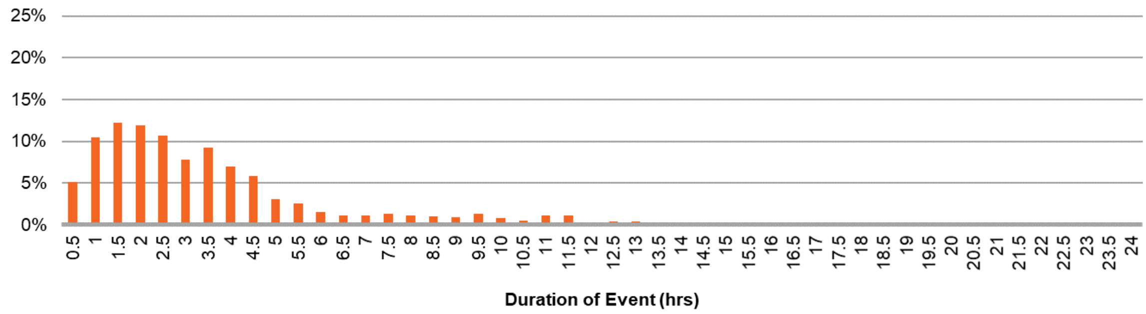
in the T-4 year due to the increase in storage capacity. These changes have resulted in lower de-rating factors for durations below these new duration thresholds in the T-1 and T-4 years. This shows that for cases adjusted to 3 hours LOLE, those with higher proportions of short-duration storage have a higher proportion of longer duration stress events. The distribution of stress events[86] in the T-1 and T-4 years is illustrated in Figure 49 and Figure 50.

Figure 49: Stress Event Duration Histogram for 2023/24 T-1 Base Case at 3 hours LOLE



Note: the mean event duration in 2023/24 is 2.9 hours

Figure 50: Stress Event Duration Histogram for 2026/27 T-4 Base Case at 3 hours LOLE



Note: the mean event duration in 2026/27 is 3.5 hours

A.8 Least Worst Regret

Details of Least Worst Regret approach and methodology can be found in page 87 of the 2017 ECR[87].

A.9 ECR Recommendations and CM Auction Summary

The ECR Data Workbook summaries the ECR recommendations, recommended demand curve target adjustments after prequalification, Secretary of State (SoS)'s decisions, capacity secured [88] (all in MW) and clearing prices (in £/kW) by auction.

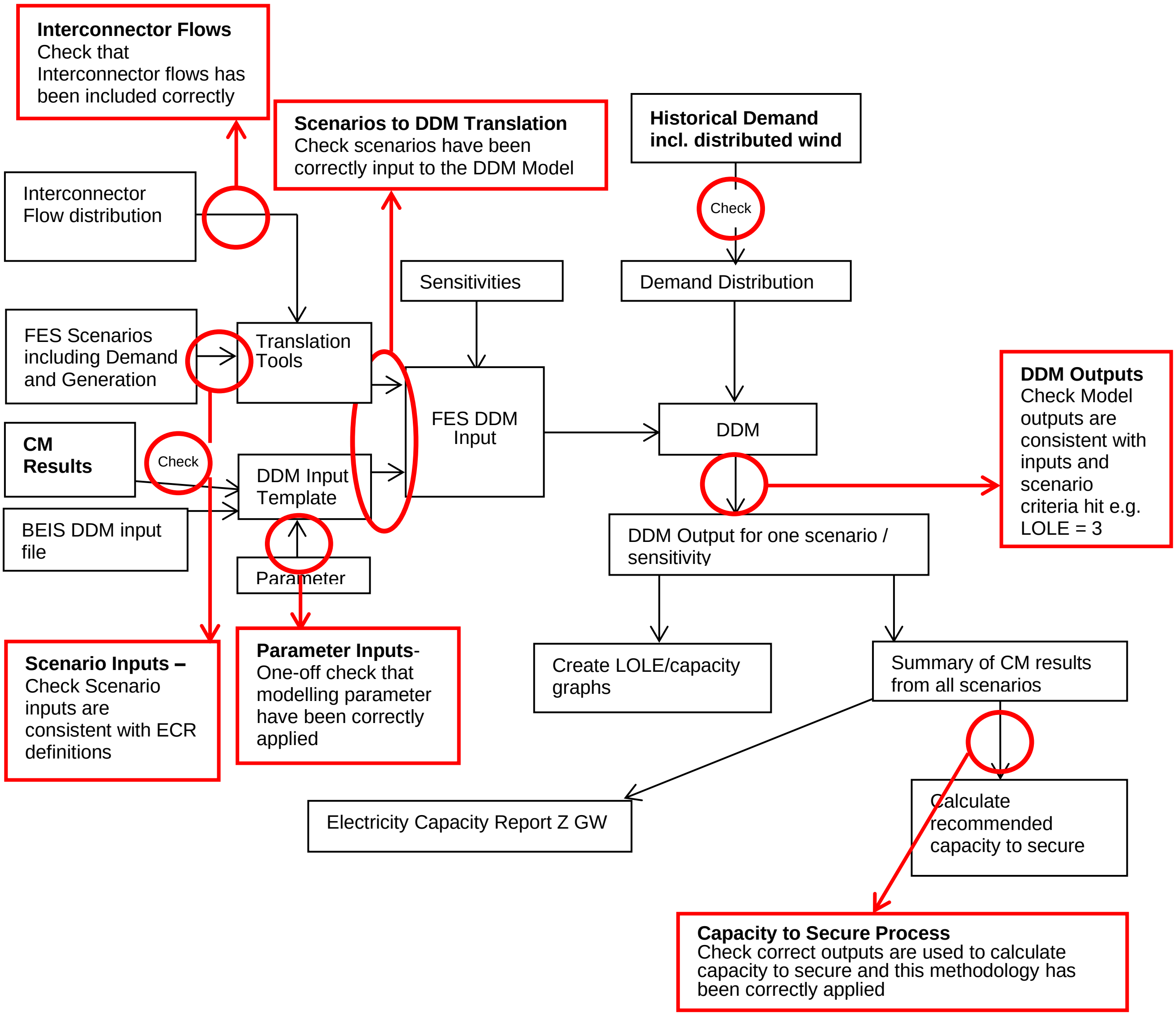
[86] Please refer to 2017 storage de-rating industry consultation (pages 27 and 28) for caveats relating to these histograms: https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/150/Duration%20Limited%20Storage%20De-Rating%20Factor%20Assessment%20-%20Final.pdf
[87] https://www.emrdeliverybody.com/Lists/Latest%20News/Attachments/116/Electricity%20Capacity%20Report%202017.pdf
[88] Note that the capacity secured in the auction shown above may not be the same as the total secured capacity reported in the latest CM registers (e.g. due to terminations or metering tests for unproven DSR etc.)

A.10 Quality Assurance

When undertaking any analysis, the Electricity System Operator (ESO) looks to ensure that a robust Quality Assurance (QA) process has been implemented. We have worked closely with BEIS's Modelling Integrity team to ensure that the QA process closely aligned to BEIS's in-house QA process[89]. We have implemented the QA in a logical fashion which aligns to the project progression, so the elements of the project have a QA undertaken when that project 'stage gate' (such as inputting data into a model) is met. This approach allows any issues to be quickly identified and rectified.

The high-level process and the points within the process where QA checks have been undertaken are shown in Figure 51.

Figure 51: QA Checks Process Diagram for each Target Year



89 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/358356/DDM_QA_Summary.pdf

The QA checks above (bordered in red) are centred on the points in the process where data is transferred from one model, or system, to another along with the model outputs. The QA is undertaken in this way as it is more straight-forward to follow which QA step is being applied at which step in the process. These steps are:

1. **Interconnector flows** – Check the interconnector flow assumption/distribution
2. **Scenario inputs** – Check the model input assumptions
3. **Parameter Inputs / CM Results/ Historical Demand Including Distributed Wind** – Check the model setup assumptions
4. **Scenarios to DDM Translation** – Check the input from the FES process into the DDM model
5. **DDM Outputs** - Check model outputs are consistent with inputs and scenario criteria
6. **Capacity to Secure Process** – Check the inputs and outputs used to determine a range and recommended capacity to secure

The detailed QA process for each of these steps is described below.

Interconnector flows

Interconnector flows assumption/distribution have been discussed with BEIS, PTE and Ofgem at various bilateral meetings. We have also consulted the results with the industry at various stakeholder events. For each scenario, the modelled interconnector flows and results are checked throughout the QA checklist process.

Scenario Inputs

The FES process is driven by extensive stakeholder engagement[90], workshops and bilateral meetings; this engagement leads to the creation of the scenarios. The constituent parts of the scenarios, for example electricity demand, are subject to internal challenge and review to ensure that they consistent and robust. Sign off is then required at senior manager level. The assumptions and outputs will be published in the annual FES document in July 2022.

For the purposes of the ECR process a check is undertaken that the inputs are consistent with the requirements of the ECR process.

Parameter Inputs / CM Results/ Historic Demand Including Distributed Wind

The parameters are set to ensure that the model runs as is required for the ECR process. These parameters are checked and documented by an analyst to ensure that they are correct and then a final template is created (with a backup) which all runs are then based on. This step also includes checking of the inputs like historical demand, demand met by distributed wind and CM Results are correctly included in the model.

[90] https://www.nationalgrideso.com/document/187746/download

Scenarios to DDM Translation

The tool for translating the FES scenarios into DDM has been documented and available for scrutiny by BEIS and the PTE. The tool includes checks that the correct information has been inputted to the model.

DDM Outputs

Each run of the analysis, including inputs and outputs, has been checked and documented internally by an analyst not involved in the ECR modelling, but familiar with the DDM and the ECR project. These documents and the associated files have been shared with BEIS to allow it to perform its own QA process.

QA Check List Process

Each run of the analysis, including inputs and outputs, is checked and documented internally by an analyst through a QA Check List process.

Capacity to Secure Process

Once all the runs have been completed the key results are used to determine the recommended capacity to secure using Least Worst Regret (LWR) tool. This process has been checked and documented internally by an analyst not involved in the ECR modelling, but familiar with the DDM and ECR project. Again, these files have been shared with BEIS to allow it to perform its own QA process.

DDM model

In addition to checks described in above figure, DDM model has been reviewed and had QA performed a number of times including:

- A peer review by Prof. Newbery and Prof. Ralph
- A review of the code by PwC
- Internal reviews by BEIS

Details of these can be found in the 2013 EMR Delivery Plan document. These imply that a further QA of the DDM is not required as part of the ECR QA process. However, to ensure that the DDM is the correct model to use, and that it is being used correctly, the PTE have been specifically asked to QA the use of DDM for ECR. In 2014, the owners of DDM, consultants Lane Clarke Peacock (LCP[91]), were asked to ensure that ESO was both using the model, and interpreting the outputs, correctly. This involved a bilateral meeting between ESO and LCP to discuss in detail the modelling being undertaken. This highlighted some minor issues which have been resolved. LCP produced a report of their QA process. The report concludes that ESO is using the model correctly and correctly interpreting the output results.

Process Overview and Governance

The process will be overseen by the PTE and they will review and report on the overall process. Internally the process has governance under Director UK Electricity System Operator.

[91] https://www.lcp.uk.com

A.11 Interconnector Modelling Assumptions

The following section presents assumptions used in BID3 for the interconnector de-rating factor calculation and a commentary on the materiality of these assumptions.

A.11.1 BID3 Assumptions

The data in Table 27 gives a high-level overview of some of the assumptions made in BID3. This covers both input data and modelling assumptions. Note that these assumptions only cover those used in the Security of Supply and LOLE modules within BID3 (these are the modules used in calculating the interconnector de-rating factors).

Table 27: BID3 Modelling Assumptions

Assumption	Source	Spatial/Temporal Resolution	Limitations/Notes
GB plant capacity	NGESO Future Energy Scenarios	By unit for transmission and larger embedded. Aggregated for smaller embedded	
Europe plant capacity	Afry scenarios	By unit for transmission, aggregated for embedded	
Plant capacity is net capacity	NGESO FES/Afry	N/A	Modelling uses net output instead of gross output
GB annual demand	NGESO FES	Annual TWh figure	BID3 has the capability to model flexible demand but this is a very new feature and was not used during this ECR. Flexible demand will become increasingly important in the future
Europe annual demand	Afry scenarios	Annual TWh figure	BID3 has the capability to model flexible demand but this is a very new feature and was not used during this ECR. Flexible demand will become increasingly important in the future
Thermal plant availability profiles	Afry	Mostly monthly or monthly business day/non-business day. Some quarterly or weekly	
Renewable plant output profiles	Afry	Mostly hourly, some hourly by month pre-2006	Reduced resolution pre-2006, currently data from 1985 – 2019 is used
Storage plant availability profiles	Afry	Monthly	Some new storage types have little or no historical data
Hydro plant availability profiles	Afry	Weekly	Only has data for a limited number of weather years, uses a default otherwise

Assumption	Source	Spatial/Temporal Resolution	Limitations/Notes
GB – Europe interconnector capacity	NGESO FES	By interconnector (not by circuit)	Not being by circuit can limit accuracy of interconnector outage modelling
Europe – Europe interconnector capacity	Afry scenarios	By interconnector (not by circuit)	Not being by circuit can limit accuracy of interconnector outage modelling
Interconnector loss rates	Afry	By interconnector (variable by direction if desired)	
GB demand profiles	Afry	Annual historical hourly, split by demand type	Data for 1985 – 2019 currently used
Europe demand profiles	Afry	Annual historical hourly, split by demand type	Data for 1985 – 2019 currently used
Short-term storage parameters	Afry	By unit	Includes MWh capacity and round-trip efficiency
Flows from non-modelled markets	NGESO/Afry	Hourly	Currently assumed to be zero (float)
LOLE module looks for tightest hours	Afry	N/A	LOLE module may model hours outside the delivery period if they are amongst the tightest 105 hours
Generation (after interconnector losses are considered) is always cheaper than load loss	Afry	N/A	BID3 modules used do not use economic data
Most markets are modelled as a single node (with no internal transmission constraints)	Afry	N/A	Currently Denmark, Italy, Norway and Sweden are modelled as more than one market

A.11.2 Markets Modelled

Table 28 shows the markets that are modelled in BID3. If a market does not appear in the table, then it is not modelled at all and any interconnection that may exist between a modelled and non-modelled market is assumed to be at float at all times.

Table 28: Markets Modelled in BID3

Country	Number of Markets Modelled	Notes
Austria	1	
Belgium	1	
Czechia	1	

Country	Number of Markets Modelled	Notes
Denmark	3	Includes Kriegers Flak offshore wind as a separate market
France	1	Does not include Corsica
Finland	1	
Germany	2	Includes Kriegers Flak offshore wind as a separate market
United Kingdom	1	Models the GB market
Ireland	1	Republic of Ireland and Northern Ireland modelled as a single market
Italy	8	
Luxembourg	2	
Netherlands	1	
Norway	5	
Poland	3	
Portugal	1	
Slovenia	1	
Spain	1	Mainland only modelled
Sweden	4	
Switzerland	1	

A.11.3 Materiality Commentary

This section is a commentary on the some of the assumptions made in BID3 and where possible the materiality to the interconnector de-rating factor calculation process. The commentary is mostly hypothesis and conjecture as it has not been thoroughly tested in BID3. However, it is included in this document to give an indication of the thought processes used by NGESO when calculating interconnector de-rating factors. We welcome any feedback on our thoughts or if you think that there are factors that we may not have appreciated fully.

Markets modelled – The current modelling includes all remote markets that are forecast to be connected to GB and also at least every market connected to the remote markets. The dataset currently used allows more markets to be modelled but this has significant implications on both the computational resource and time required to run the analysis. It is assumed that no power flows in either direction on the interconnectors between modelled and non-modelled markets. A potential compromise is to use fixed flows on these interconnectors.

Interconnectors – The AC interconnectors are not modelled with as much detail as the DC interconnectors. This is primarily an issue with the difficulty of selecting a single value for parameters, such as capacity and losses, for AC interconnectors when compared to DC interconnectors. Some testing has been carried out by NGESO varying AC interconnector losses which demonstrates that the interconnector de-rating factors are not very sensitivity to changes in this parameter.

Random outages – The current version of BID3 only models random outages for discrete thermal units (i.e. not including small aggregated units). Historical average availabilities are used to create a deterministic percentage for all other generator types (intermittent renewable, storage, hydro and aggregated thermal units). The dataset used does not have enough information in it to discretise most of the generator types to allow random outages to be used. Therefore, further data and modifications to BID3 would be required to extend the random outage methodology to other generator types. There would also be a penalty in terms of the computational resource required as the complexity of the modelling would be increased.

Station demand – The capacity that appears in the scenarios is net capacity of the unit (i.e. gross capacity minus station demand). When a unit has randomly been determined to be on forced outage then it is assumed that the capacity of the unit is zero. For a number of technology types this is not correct as there will be residual station demand after a trip. This is not currently modelled in BID3 and therefore may over-estimate the capacity available in a market.

Plant availability profiles – The availability profiles in BID3 are based upon historical availability data. This may not be accurate for a number of reasons. Firstly, unit availability may change in the future (for example as a unit comes towards the end of its' operating life). Secondly, there are new unit designs (e.g. EPR nuclear reactors) and new technologies (e.g. compressed air storage) for which there is very little or no historical availability data to work from. Thirdly, there may be some issues when a unit first commissions (this may be even more prevalent where the unit is the first of a kind) that alters the availability in the early period of operation. Using historical data is probably the best option available and therefore an unavoidable assumption in BID3.

Internal transmission constraints – Excepting those countries that are modelled as more than one market in Table 28, no internal transmission constraints are modelled in BID3. Each market is modelled as a node. It is assumed that power can flow through a market without constraint from one interconnector to the next. Clearly this is a simplification, but it is made to make sourcing data easier and reduce the computational effort required. The risk of an internal constraint being present increases as the number of markets through which the power must flow increases.

Demand types – BID3 allows for different types of demand, which allows for different demand profiles. This is useful to model new trends in demand such as heat pumps or electric vehicles. At present there is not much data on how these new demand types may be profiled throughout the year. A limitation of the module used in BID3 in previous years is that it ignored flexible demand types. This was not a problem for pure demand as it can be assumed that flexible demand will not be present during times of system stress. However, the limitation also excluded demand types that can discharge back into the grid, such as in vehicle-to-grid. This was a known problem expected to become more of an issue as this technology becomes more widespread. A recent update to the module now provides the ability to model flexible demand. This new capability was not used in the current ECR as it was deemed that there was insufficient time to test it with our bespoke datasets. At present we believe that this limitation does not materially affect the interconnector de-rating factors but is likely to in the future and we will work to include this new capability in our modelling in future years.

A.12 Interconnector Derating Factor Percentiles

Average annual interconnector derating factors for each scenario and sensitivity have been calculated as the average of the distribution of hourly derating factors over 1000 random outage cases. In this year's ECR for the first time we have supplemented these average derating factors with the percentiles of each distribution. The motivation behind the publication of percentiles is that distinctly different distributions can possess similar averages whilst displaying a markedly different risk profile to consumers.

Take for instance a Gaussian like distribution centred on a derating factor of 50 per cent with a standard deviation of 10 per cent. Our understanding of Gaussian statistics tells us that 68.2 per cent of all derating factors lie within the range of 40-60 per cent etc.

Now consider a bimodal distribution where derating factors are distributed equally between zero per cent and 100 per cent. Both distributions have an average of 50 per cent but the latter distribution presents significantly more risk to consumers because the probability of zero interconnector flow is much greater in a world governed by this distribution.

In Figure 52 to Figure 56 we show percentile plots for each country within each scenario and sensitivity combination. Percentiles are plotted as a function of interconnector derating factor. One can interpret the x-axis as the estimated probability of seeing an hourly derating factor of less than or equal to the corresponding value on the y-axis. The same characteristic curve is seen for all derating factor percentile plots. The shape of the curve indicates that derating factors are distributed within highly bimodal distributions with modes centred on zero and one hundred. This is indicative of world in which the interconnector in question is either importing to Great Britain at the full capacity in a given hour or not at all. Intuitively this is telling us that when Great Britain has a stress period, other neighbouring countries in Europe may also be experiencing a stress period at the same time, meaning imports are unavailable; if neighbouring countries are not experiencing a stress period, there is sufficient capacity in Europe to provide full imports to Great Britain, driven by high scarcity prices here.

The detailed view of the underlying derating factor distributions offered by percentiles allows us to consider whether the mean average is an appropriate description of central tendency to measure interconnector derating factors. A disadvantage of the mean is that it is biased to the presence of outliers, i.e. the presence of a small number of data points that are much larger or smaller than is typical for the distribution can significantly skew the measurement. Often the median (50th-percentile) is used as an outlier resistant measure of central tendency. Another approach takes the mean over a range limited by the percentiles that include the vast majority of data points and omit as many outliers as possible. An alternative approach is simply to take a percentile other than the median but this is usually an arbitrary choice.

The nature of the percentile plots presented here is much like the second case described above, i.e. there is significant risk of zero imports during any given hourly period within a stress event. Therefore, any measure of central tendency must convey this risk. In most cases the probability of seeing a derating factor of 100 percent is much higher than the probability of seeing a derating factor of zero. Taking the median to describe the central tendency often results in interconnector derating factors of 100 per cent, which clearly does not reflect the risk of zero flows. The alternative approach described above, taking the mean over a range limited by a lower and upper percentile would be unhelpful here as would mean clipping data from the two prominent modes.

The point here is really that while the two modes of these distributions are imbalanced, neither is a set of outlying points and both lie at the extreme opposite ends of the distributions. The mean average should therefore naturally be weighted towards an appropriate level of risk and is a good measure of central tendency for distributions of this nature.

Figure 52: Base Case interconnector de-rating factors – cumulative probability

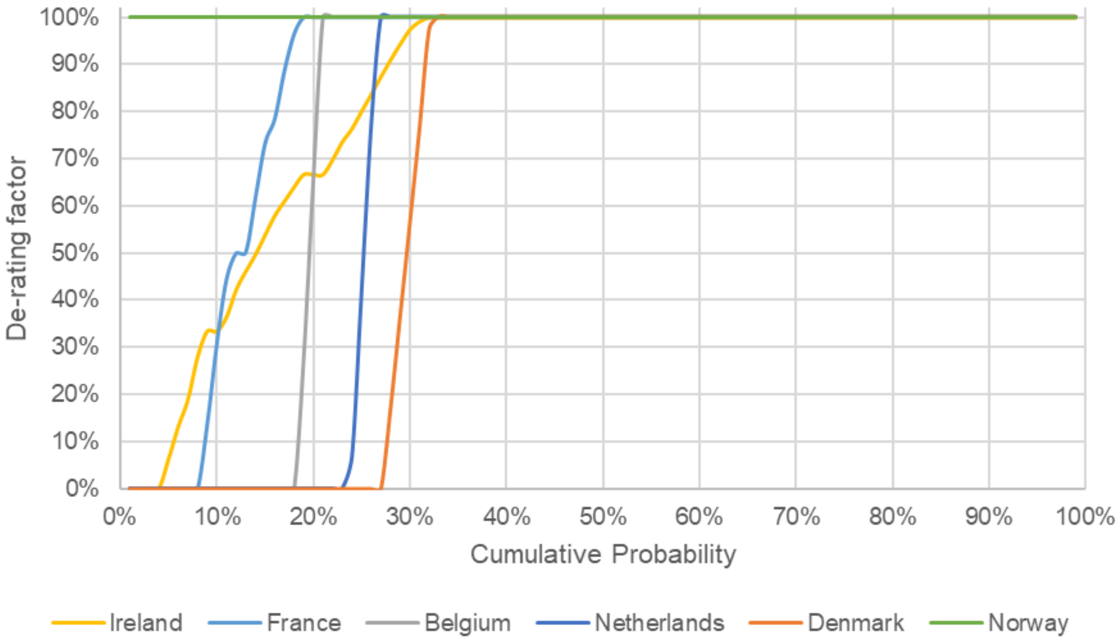


Figure 53: Consumer Transformation interconnector de-rating factors – cumulative probability

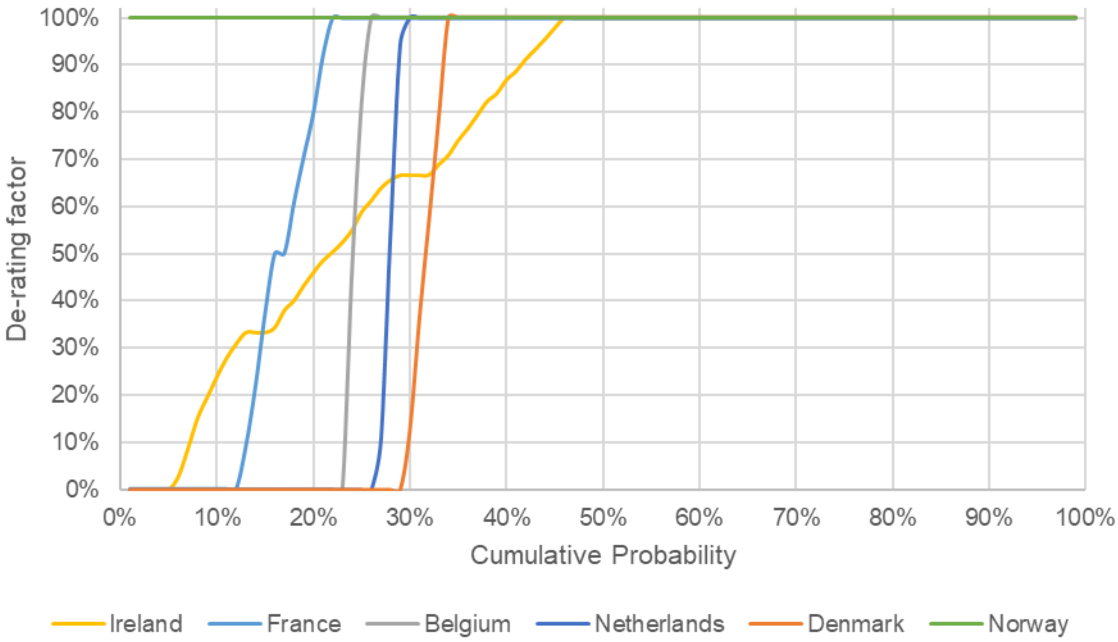


Figure 54: System Transformation interconnector de-rating factors – cumulative probability

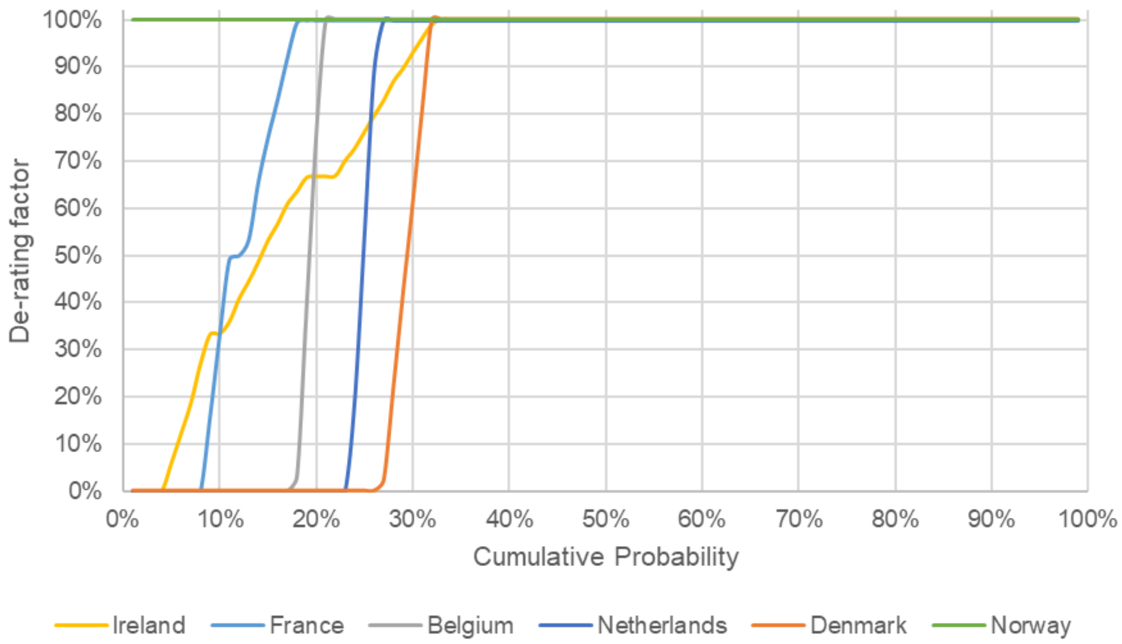


Figure 55: Leading the Way interconnector de-rating factors – cumulative probability

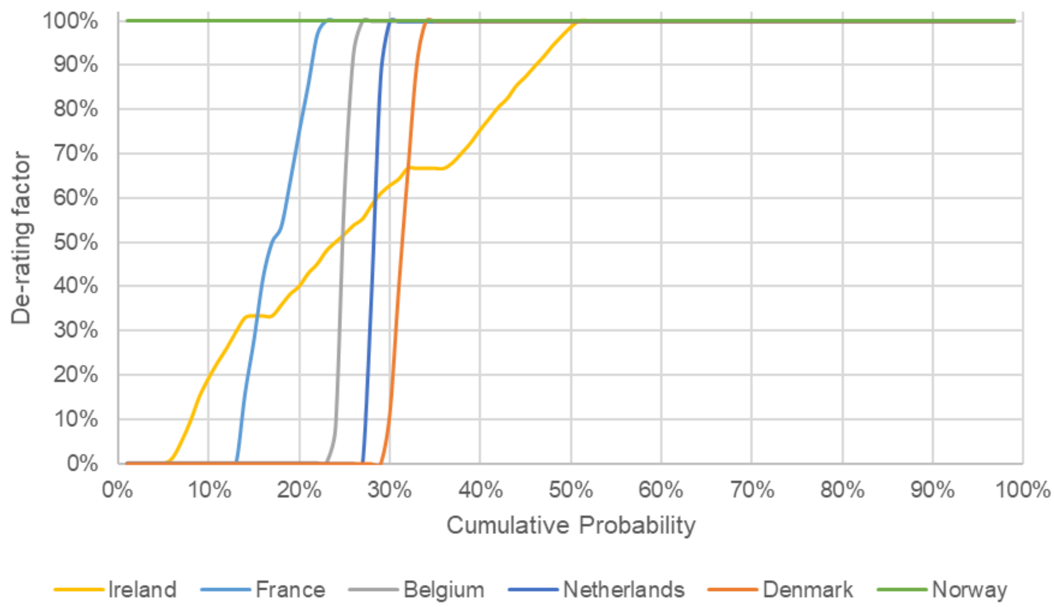
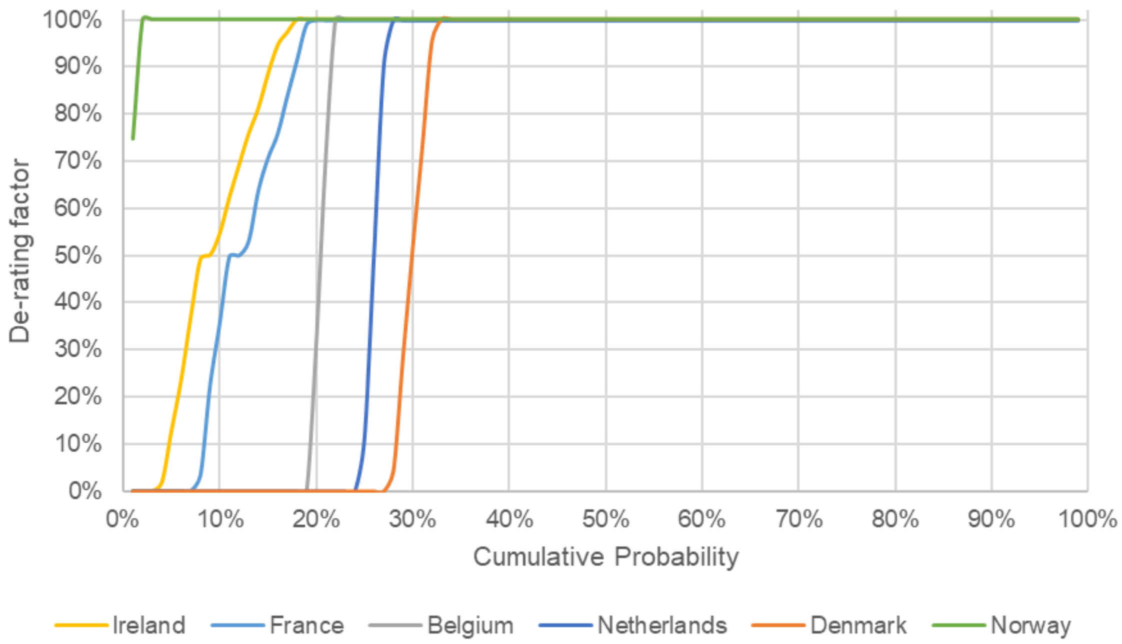


Figure 56: Falling Short interconnector de-rating factors – cumulative probability



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